TITLE 20 ENVIRONMENTAL PROTECTION
CHAPTER 2 AIR QUALITY (STATEWIDE)
PART 50 OIL AND GAS SECTOR – OZONE PRECURSOR POLLUTANTS

20.2.50.1 ISSUING AGENCY: Environmental Improvement Board.
[20.2.50.1 NMAC – N, XX/XX/2021]

20.2.50.2 SCOPE: This Part applies to sources located within areas of the state under the board's jurisdiction that, as of the effective date of this Part~~rule or anytime thereafter~~, have ~~are causing or contributing to~~ ambient ozone concentrations that exceed ninety-five percent of the national ambient air quality standard for ozone, as measured by a design value calculated and based on data from one or more department monitors. ~~Once a source 12 becomes subject to this rule, the requirements of the rule are irrevocably effective unless the source obtains a 13 federally enforceable air permit limiting the potential to emit to below such applicability thresholds established in 14 this Part.~~ As of the effective date, sources located in the following counties of the state are subject to this Part: Dona Ana, Eddy, Lea, Sandoval, San Juan, and Valencia.

A. If, at any time after the effective date, any area in the state is determined by the department to have exceeded ninety-five percent of the national ambient air quality standard for ozone, as measured by a design value calculated and based on data from one or more department monitors, the department shall revise this rule to incorporate such areas consistent with Sections 74-1-9 and 74-2-6 NMSA. The notice of proposed rulemaking shall be published no less than one hundred and eighty (180) days before the sources in the affected area will become subject to this Part and shall include the monitoring ~~, testing, or inspection~~ data, and all other technical information, that demonstrate that the area or areas ~~the~~ subject ~~of~~ to the proposed rulemaking exceed ninety-five percent of the national ambient air quality standard for ozone.

(1) The proposed rule revision shall include, in addition to the requirements of 20.1.1.301.B. NMAC:

(a) a list of the areas that the board proposes to become subject to this Part, and the date upon which the sources in the relevant area (or areas) will become subject to this Part; and

(b) proposed implementation dates, consistent with the time provided in the phased implementation schedules provided for in each Section of this Part, for sources within the area or areas ~~the~~ subject~~(s) of~~ to the proposed rulemaking to come into compliance with each Section of this Part.

B. Once a source becomes subject to this rule based upon potential to emit, any the requirements of the rule based upon potential to emit are irrevocably effective unless the source obtains a federally enforceable, or legally and practically enforceable limit on the potential to emit to below such applicability thresholds established in this Part, or the relevant section contains a threshold below which the requirements no longer apply.

[20.2.50.2 NMAC – N, XX/XX/2021]

Comment on 20.2.50.2: The schedules set forth in Section 50 afford sources a tiered schedule to address each subject unit. This redline addresses sources and areas that become subject to this Part after the effective date and provides a process for orderly inclusion of the newly affected sources and areas within the scope of the rule. This change is needed to provide assurance that sources will have sufficient notice and due process to incorporate changes. This revision also addresses the conditions under which a source may take enforceable limits to reduce emissions below the applicability thresholds of the standards and when sources must do so, including accounting for off-ramps contained within the regulations. This change is needed to provide clarity on how the applicability thresholds in the various standards should be interpreted.

This change also addresses the counties that are within the statutory authority of NMED to regulate under Section 74-2-5 NMSA 1978. Rio Arriba has not been included because its current design value is below 95% of the NAAQS, and Chavez has not been included because it has no monitor and hence no design value.

20.2.50.3 STATUTORY AUTHORITY: Environmental Improvement Act, Section 74-1-1 to 74-1-16 NMSA 1978, including specifically Paragraph (4) and (7) of Subsection A of Section 74-1-8 NMSA 1978, and Air Quality Control Act, Sections 74-2-1 to 74-2-22 NMSA 1978, including specifically Subsections A, B, C, D, F, and G of Section 74-2-5 NMSA 1978 (as amended through 2021).
[20.2.50.3 NMAC - N, XX/XX/2021]

20.2.50.4 DURATION: Permanent.
[20.2.50.4 NMAC - N, XX/XX/2021]

20.2.50.5 EFFECTIVE DATE: Month XX, ~~2021~~2022, except where a later date is specified in another Section.
[20.2.50.5 NMAC - N, XX/XX/2021]

20.2.50.6 OBJECTIVE: The objective of this Part is to establish emission standards for volatile organic compounds (VOC) and oxides of nitrogen (NOx) for oil and gas production, processing, and natural gas transmission sources.
[20.2.50.6 NMAC - N, XX/XX/2021]

20.2.50.7 DEFINITIONS: In addition to the terms defined in 20.2.2 NMAC - Definitions, as used in this Part, the following definitions apply.

A. "Approved instrument monitoring method" means an optical gas imaging, United States environmental protection agency (U.S. EPA) reference method 21 (RM21) (40 CFR 60, Appendix B), or other instrument-based monitoring method or program approved by the department in advance and in accordance with 20.2.50 NMAC.

B. "Auto-igniter" means a device that automatically attempts to relight the pilot flame of ~~in the combustion chamber of~~ a control device in order to combust VOC emissions, or a device that will automatically attempt to combust the VOC emission stream.

Comment on 20.2.50.7(B): This change is needed because the open flare section includes use of auto ignitors. Open flares do not have a combustion chamber.

C. "Bleed rate" means the rate in standard cubic feet per hour at which ~~natural~~ gas is continuously ~~or intermittently~~ vented from a pneumatic controller.

Comment on 20.2.50.7(C): NMOGA requests that "intermittent" be removed from this definition to align with the federal and other state interpretations of "bleed rate," which exclusively refer to a continuous rate. See e.g., 40 C.F.R. 60.5430a (NSPS OOOOa). The bleed rate refers to the rate at which gas is consistently and continuously emitted to atmosphere or to a capture system between actuations. Intermittent controllers do not bleed continuously. Furthermore, both intermittent controllers and continuous bleed controllers actuate and release or vent emissions periodically. This is not the bleed rate and as proposed by NMED, this intermittent actuation could be inappropriately correlated with the bleed rate. To avoid inconsistency and confusion, NMED should similarly remove the term "intermittent bleed rate" from the recordkeeping requirement in 20.2.50.122(D)(5)(e). Further, pneumatic controllers operate on any pressurized gas (natural gas, air, nitrogen, etc.). This definition should be agnostic as to which gas is being used, and sections where this term is used should make it clear how those provisions apply depending on the gas being used.

D. "Calendar year" means a year beginning January 1 and ending December 31.

E. "Centrifugal compressor" means a machine used for raising the pressure of natural gas by drawing in low-pressure natural gas and discharging significantly higher-pressure natural gas by means of a mechanical rotating vane or impeller. Screw, sliding vane, and liquid ring compressor is not a centrifugal compressor.

F. "Closed vent system" means a system that is designed, operated, and maintained to route the VOC emissions from a source or process to a process stream or control device with minimal ~~no~~ loss of VOC emissions to the atmosphere.

Comment on 20.2.50.7(F): Change is required for technical feasibility purposes as there is no way to guarantee no loss of VOC emissions from closed vent system at all times.

G. "Commencement of operation" means for an oil and natural gas wellhead, the date any permanent production equipment is in use and product is consistently flowing to a sales lines, gathering line or storage vessel from the first producing well at the stationary source~~, but no later than the end of well completion operation~~.

Comment on 20.2.50.7(G): Change is required to account for instances where a well is waiting on surface equipment or a gathering line to begin production. Especially considering the recently adopted regulations from the Oil Conservation Commission, first production may be delayed awaiting gas pipeline takeaway. This may be weeks or even months after the end of completion operations on wells associated with a Well Production Facility. Commencement of operation should not begin until production to sales occurs.

H. "Component" means a pump seal, flange, pressure relief device (including thief hatch or other opening on a storage vessel), connector or valve that contains or contacts a process stream with hydrocarbons, except for components where process streams consist solely of glycol, amine, produced water or methanol.

I. "Connector" means flanged, screwed, or other joined fittings used to connect pipe line segments, tubing, pipe components (such as elbows, reducers, "T's" or valves) to each other; or a pipe line to a piece of equipment; or an instrument to a pipe, tube or piece of equipment. A common connector is a flange. Joined fittings welded completely around the circumference of the interface are not considered connectors for the purpose of this Part.

J. **"Construction"** means fabrication, erection, or installation ~~or relocation~~ of a stationary source, ~~including~~ but does not include ~~limited to~~ relocation, replacement in-kind, temporary installations, ~~and~~ or portable stationary sources.

Comment on 20.2.50.7(J): Defining "construction" to mean "relocation" would result in the frequent and unnecessary prompting of new control requirements for portable stationary sources, which are specifically included in NMED's proposed definition. The proposed definition presents a particular concern for portable engines which are routinely relocated throughout a field. "Relocation" is incongruent with the terms "fabrication," "erection," or "installation," which are more associated with the introduction of a new stationary source at a location rather than the movement of an existing stationary source. The inclusion of "relocation" would be inconsistent with EPA's definition of "construction" under the NSPS and NESHAP regulations and NMED's definition of "construction" as used in the issuance of construction permits, none of which consider relocation to be construction. See 40 C.F.R. §§ 60.2, 63.2; 20.2.72.7 NMAC. Defining construction to include relocation may disincentivize operators from relocating oversized assets when well production declines. For example, an existing compressor may become oversized as well production decreases. Whereas an operator would normally change this unit out for a smaller, more appropriately sized compressor, operators may retain the larger and higher-emitting compressor to avoid triggering new standards. Portable engines are also regulated as nonroad engines, and states are generally preempted from regulating emissions from these units.

K. **DELETED**~~**"Custody transfer"** means the transfer of oil or natural gas after processing or treatment in the producing operation, or from a storage vessel or automatic transfer facility or other processing or treatment equipment including product loading racks, to a pipeline or any other form of transportation.~~

Comment on 20.2.50.7(K): Deletion requested as "Custody transfer" is only used in connection with "Local distribution custody transfer", a term that is defined separately at 20.2.50.7.V. Potential for future conflicting definitions.

L. **"Control device"** means air pollution control equipment or emission reduction technologies that thermally combust, chemically convert, or otherwise destroy or recover air contaminants. Examples of control devices include but are not limited to open flares, enclosed combustion devices (ECDs), thermal oxidizers (TOs), vapor recovery control units (VRCUs), fuel cells, condensers, ~~air fuel ratio controllers (AFRs),~~ catalytic converters (oxidative, selective, and non-selective), or other equipment for the sole purpose of emission reduction ~~equipment~~. A control device may also include any other air pollution control equipment or emission reduction technologies approved by the department in an operating permit. ~~to comply with emission standards in this Part.~~

Comment on 20.2.50.7(L): Redline required to clarify the difference between vapor recovery units and vapor recovery control units. Vapor recovery units or towers can be utilized as process equipment or to control emissions from a process. EPA and NMED have long recognized this distinction and have employed a three-factor test to determine which VRUs are fairly regarded as a control device and subject to control device standards. See comment on 20.2.50.7(TT).
Redline required as an AFR does not thermally combust, chemically convert, or otherwise destroy or recover air contaminants and should not be considered a control device in the context of this rule. AFRs are considered process control devices, not control devices as per the screening process provided by EPA for vapor recovery units being considered "control" (paraphrased as follows):
Operator must answer the following three questions:
(1). Is the primary purpose of the equipment to control air pollution?
(2). Where the equipment is recovering product, how do the cost savings from the product recovery compare to the cost of the equipment?
(3). Would the equipment be installed if no air quality regulations were in place?

This redline also ensures that equipment must be used for the sole purpose of emission reductions before it is considered a control device. Oil and natural gas systems are complex, and often gases are routed to pilots and other combustion devices without being control devices. Further, NMOGA believes that it should be clarified that devices used during temporary events (maintenance, malfunction, etc.) should not be considered control devices and thus subject to the most rigorous requirements of devices used for more permanent events.

M. **"Department"** means the New Mexico environment department.
N. **"Downtime"** means the period of time when equipment is inoperable ~~not in operation, or when a well is producing, and the control device is not in operation.~~

Comment on 20.2.50.7(N): Redline is required for technical clarification. Just because something is not in operation doesn't mean it is out of service. For instance, a flare that is only used during pigging or loading operations. Similarly, there may be *instances where a well is producing and a control device is not operating on location because that particular piece of equipment is not operating. For instance, a wellsite compressor may not be operating and hence the AFR and catalytic converter are not operating – but they are not needed for the well and other production equipment to operate properly.*

O. "Enclosed combustion device" means a combustion device where waste ~~gaseous~~ gas ~~fuel~~ is combusted in an enclosed chamber solely for purpose of destruction. This may include, but is not limited to an enclosed flare or combustor. ~~, reboiler, and heater.~~

Comment on 20.2.50.7(O): Redline required to clarify that enclosed combustion devices should be regulated as control devices only where their purpose is to reduce emissions, as opposed to combustion devices used for purposes unrelated to emissions reduction (e.g., heaters or reboilers used to provide heat to a process).

P. "Existing" means constructed or reconstructed before the effective date of this Part and has not since been modified or reconstructed.

Q. "Gathering and boosting ~~station~~site" means a permanent combination of equipment located downstream of a well production facility that: collects or moves ~~natural gas, crude oil, condensate~~natural gas prior to the inlet of a natural gas processing plant or prior to a natural gas transmission pipeline or transmission compressor station if no gas processing is performed; or collects, moves, or stabilizes crude oil or condensate prior to an oil transmission pipeline or other form of transportation. ~~, or produced water between a wellhead site and a midstream oil and natural gas collection or distribution facility, such as a storage vessel battery or compressor station, or into or out of storage~~

Comment on 20.2.50.7(Q): Redline required to limit definitions to gathering and boosting stations and not transmission compression stations, which are covered below by new revised definition. Change from "station" to "site" is needed to align with other uses of the term throughout the rule. Change from wellhead site to well production facility required to clarify scope. Wellhead site implies only equipment at the wellhead pad, but not potentially centralized facilities remote from the wellhead pad servicing the production from that wellhead pad. Additional changes were required to clarify the end point on both the natural gas chain/line and the crude oil/condensate chain/line. See also definition of Well Production Facility, below.

NMOGA does not support the revised definition in NMED Exhibit 41, as the industry believes the definition provided here better defines the term.

R. "Glycol dehydrator" means a device in which a liquid glycol absorbent, including ethylene glycol, diethylene glycol, or triethylene glycol, directly contacts a natural gas stream and absorbs water.

S. "Hydrocarbon liquid" means any naturally occurring, unrefined petroleum liquid and can include oil, condensate, and intermediate hydrocarbons. Hydrocarbon liquid does not include produced water.

Comment on 20.2.50.7(S): Addition is needed to clarify that produced water is not considered a "hydrocarbon liquid". This is necessary because produced water may contain a very small amount of hydrocarbons. This change makes it clear that this rule does not treat produced water as a hydrocarbon liquid even when it contains a minor amount of hydrocarbons.
Redline required to align with other Parts requiring vapor capture during transfer of hydrocarbon liquid. Vapor capture for produced water storage is technically infeasible for sites utilizing VRCUs.

T. "Liquid unloading" means the removal of accumulated liquid from the wellbore that reduces or stops natural gas production.

U. "Liquid transfer" means ~~the loading and~~ unloading of a hydrocarbon liquid ~~or produced water~~ between a storage vessel and tanker truck or tanker rail car for transport.

Comment on 20.2.50.7(U): Redline required to remove produced water because the only time the term "liquid transfer" is used in this part is in section 20.2.50.120, Hydrocarbon Liquid Transfers, and produced water is not a "hydrocarbon liquid" within the meaning of the rule. The removal of "or produced water" makes it clear that transfers of produced water are not included in that section. NMOGA does not believe it was NMED's intent to include produced water within the scope of 20.2.50.120, nor does NMOGA believe inclusion would be appropriate. Relative to the unrefined petroleum liquids covered by section 20.2.50.120, produced water has low emissions potential and does not warrant the rigorous controls mandated. For example, requiring produced water trucks to meet vapor tightness standards that ordinarily apply only to gasoline cargo tanks (40 C.F.R. Part 63, Subpart R) would be a significant overreach, as vapor losses from gasoline vastly outweigh vapor losses from produced water. This would also be extremely disruptive: because produced water vehicles are generally not certified or designed to transport hazardous materials, NMED's proposal would require a significant adjustment by the transportation industry and disrupt interstate commerce by imposing more stringent standards on transport than federal hazardous material *law.*

V. "Local distribution company custody transfer station" means a metering station where the local distribution (LDC) company receives a natural gas supply from an upstream supplier, which may be an interstate transmission pipeline or a local natural gas producer, for delivery to customers through the LDC's intrastate transmission or distribution lines.

W. "~~Natural gas~~Transmission compressor station" means any permanent installation of one or more compressors that move ~~designed to compress~~ pipeline quality natural gas at increased pressure from production fields, ~~well pressure to gathering system pressure before the inlet of a~~ or natural gas processing plants, ~~or to move compressed natural gas~~ through a transmission pipeline for ultimate delivery to the local distribution company custody transfer station, into underground storage, or other industrial end users.

Comment on 20.2.50.7(W): Redline required to clarify that, when the term natural gas compressor station is used in the rule, it refers to transmission compressor stations. There are two types of compressor stations for purposes of the rule: those located at gathering and boosting sites and those used in transmission. In addition, compressors can be located at well production facilities. Those located at well production facilities are excluded from section 20.2.50.114 standards. Those located at gathering and boosting sites are already included in the term "gathering and boosting site," which includes permanent installations, such as compressor stations, downstream of production and upstream of the natural gas processing plant. The only other type of compressor station under the terms of the rule is transmission compressor stations, which are included in this revised definition.

NMOGA does not support the revised definition in NMED Exhibit 41, as the industry believes the definition provided here better defines the term.

X. "Natural gas-fired heater" means an enclosed device using a controlled flame and with a primary purpose to transfer heat directly to a process material or to a heat transfer material for use in a process.

Y. "Natural gas processing plant" means the processing equipment engaged in the extraction of natural gas liquid from natural gas or fractionation of mixed natural gas liquid to a natural gas product, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

Z. "New" means constructed or reconstructed on or after the effective date of this Part.

AA. "Non-Emitting Controller" means a device that monitors a process parameter such as liquid level, pressure or temperature and sends a signal to a control valve in order to control the process parameter and does not emit natural gas to the atmosphere. Examples of non-emitting controllers include but are not limited to: instrument air or inert gas pneumatic controllers, electric controllers, mechanical controllers and Routed Pneumatic Controllers.

Comment on 20.2.50.7(AA): This term is recommended to clarify what controllers are understood to be non-emitting as referenced in 20.2.50.122. All controllers that do not emit natural gas to the atmosphere under normal operations should be considered non-emitting for the purposes of this part.

BB. "Operator" means the person or persons responsible for the overall operation of a stationary source.

~~BB~~CC. "Optical gas imaging (OGI)" means an imaging technology that utilizes a high-sensitivity infrared camera designed for and capable of detecting hydrocarbons.

~~CC~~DD. "Owner" means the person or persons who owns a stationary source or part of a stationary source.

~~DD~~EE. "Permanent pit or pond" means a pit or pond used for collection, retention, or storage of produced water or brine and is installed for longer than one year.

Comment on 20.2.50.7(EE). Redline needed to align with revisions to 20.2.50.126.

~~EE~~FF. "Pneumatic controller" means a device that monitors a process parameter such as liquid level, pressure, or temperature and uses pressurized gas (which may be released to the atmosphere during normal operation) to send a signal to a control valve in order to control the process parameter. Controllers that do not utilize pressurized gas are not pneumatic controllers.~~an instrument that is actuated using pressurized gas and used to control or monitor process parameters such as liquid level, gas level, pressure, valve position, liquid flow, gas flow, and temperature.~~

i. "High-Bleed Pneumatic Controller" means a continuous bleed pneumatic controller that is designed to have a continuous bleed rate that emits in excess of 6 standard cubic feet per hour (scfh) of ~~natural~~ gas to the atmosphere.

ii. "Low-Bleed Pneumatic controller" means a continuous bleed pneumatic controller that is designed to have a continuous bleed rate that emits less than or equal to 6 scfh of ~~natural~~ gas to the atmosphere.

iii. "Intermittent pneumatic controller" means a pneumatic controller that is not designed to have a continuous bleed rate, but is designed to only release ~~natural~~ gas above de minimis amounts to the atmosphere as part of the actuation cycle.

iv. "Routed Pneumatic Controller" means a pneumatic controller of any type that releases natural gas to a process, sales line or to a combustion device instead of directly to the atmosphere.

Comment on 20.2.50.7(FF): Redline proposed to provide better clarity and differentiate between a pneumatic controller and a control valve. Pneumatic devices are powered by pressurized gas, including natural gas, air, nitrogen, etc. This definition should be agnostic as to the gas being used, and section 20.2.50.122 Pneumatic Controllers and Pumps should be clear what regulations apply to various pneumatic devices based in part on what gases are used for actuation.

Comment on 20.2.50.7(FF)(i)-(iv): Redline required to provide clarification between controller types. NMOGA has proposed use of terms from Colorado's pneumatics rulemaking which has undergone significant discussion and engagement over the past several years. These definitions were agreed upon by environmental organizations, local governments, industry and the agency. NMOGA suggests NMED adopt specific definitions for the various types of pneumatic controller for clarity in the implementation of the proposed pneumatic controller facility-wide plan. These classifications/terms have been incorporated into the proposed redlines for ease of reference in the rule. These classifications correspond with how vendors sell these devices. Using these definitions will allow use of the vendor's classification for compliance purposes. NMOGA has also proposed a definition of "non-emitting pneumatic controller" to facilitate implementation of 20.2.50.122's phase out provisions.

~~FF~~GG. "Pneumatic diaphragm pump" means a positive displacement pump powered by pressurized ~~natural~~ gas that uses the reciprocating action of flexible diaphragms in conjunction with check valves to pump a fluid. A pump in which a fluid is displaced by a piston driven by a diaphragm is not considered a diaphragm pump. A lean glycol circulation pump that relies on energy exchange with the rich glycol from the contactor is not considered a diaphragm pump.

Comment on 20.2.50.7(GG): Pneumatic diaphragm pumps are driven by pressurized gas including natural gas, air, nitrogen, etc. This definition should be agnostic as to the particular gas being used, and section 20.2.50.122 Pneumatic Controllers and Pumps should be clear what regulations apply to various pneumatic devices based in part on what gases are used for actuation.

~~GG~~HH. "Potential to emit (PTE)" means the maximum capacity of a stationary source to emit an air ~~contaminant~~ pollutant under its physical and operational design. ~~The~~ Any physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and ~~a~~ restrictions on the hours of operation or on the type or amount of material combusted, stored or processed, shall be treated as part of its design if the limitation is federally enforceable or legally and practically enforceable in an operating permit, authorization, or other requirement established under a federal, state, local or tribal authority. The PTE for nitrogen dioxide shall be based on total oxides of nitrogen.

Comment on 20.2.50.7(HH). Redline required to recognize all effective and enforceable means of reducing potential emissions that are available under New Mexico law. The prior definition only recognized limitations that are "federally enforceable" and did not clearly allow consideration of other legally and practically enforceable limitations. Including these broader concepts in the definition of PTE encourages consistency with other areas of New Mexico law where PTE is defined similarly. See, e.g., 20.2.79.120.B(2) NMAC (recognizing limitations enforceable as a practical matter). It is further important that operators can take into account state only permit requirements or other state only requirements in determining PTE

~~HH~~II. "Produced water" means a ~~fluid~~ liquid that is an incidental byproduct from ~~drilling for or~~ well completion and the production of oil and gas.

Comment on 20.2.50.7(II): Redline required for technical clarification. Produced water is produced during completions and production, not drilling operations. The Groundwater Protection Council provides the following definition of produced water, which is illustrative: "Produced water is defined as the water that exists in subsurface formations and is brought to the surface during oil and gas production. Water is generated from conventional oil and gas production, as well as the production of unconventional sources such as coal and bed methane, tight sands, and gas shale." https://www.gwpc.org/topics/produced-water.

~~II~~JJ. "Produced water management unit" means a recycling facility or a permanent pit or permanent pond that is a natural topographical depression, man-made excavation, or diked area formed primarily of earthen materials (although it may be lined with man-made materials), which is designed to accumulate produced water and has a design storage capacity equal to or greater than 50,000 barrels.

Comment on 20.2.50.7(JJ): Redline required as recycling facilities do not align with PWMU requirements of this part. Oil and natural gas operations commonly extract saltwater from the earth as part of the production process. Operators can recycle the water, inject it back into working reservoirs for reuse, or discard it at a saltwater disposal site. When the waste reaches a saltwater disposal or recycle facility, it goes into steel tanks where the various byproducts are separated out. From there, the facility uses pumps to inject the water into underground porous rock formations sealed by impermeable strata. This clarifies that the scope of units/sources that are produced water management units is based primarily on those with large (greater than 50,000 barrel) permanent ponds/pits and also any associated equipment used for recycling.

~~JJ~~KK. "Qualified Professional Engineer" means an individual who is licensed by a state as a professional engineer to practice one or more disciplines of engineering and who is qualified by education, technical knowledge, and experience to make the specific technical certifications required under this Part.

~~KK~~LL. "Reciprocating compressor" means a piece of equipment that increases the pressure of process gas by positive displacement, employing linear movement of a piston rod.

~~LL~~MM. "Reconstruction" means a modification that results in the replacement of the components or addition of integrally related equipment to an existing source, to such an extent that the fixed capital cost of the new components or equipment exceeds fifty percent of the fixed capital cost that would be required to construct a comparable entirely new facility.

MM. "Recycling facility" means a stationary or portable facility used exclusively for the treatment, reuse, or recycling of produced water and does not include oilfield equipment ~~such as separators, heater treaters, and scrubbers~~ in which produced water may be used.

Comment on 20.2.50.7(MM): NMOGA requests that references to specific oilfield equipment be removed to avoid confusion. For example, "separators" may include equipment used in the industry that should not be included within the scope of a recycling facility.

NN. "Responsible official" means one of the following:

(1) for a corporation: president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of the corporation if the representative is responsible for the overall operation of the ~~source~~subject unit and either (a) the facilities employ more than 250 persons or have gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars), or (b) the delegation of authority to such representative is approved in advance by the department.

(2) for a partnership or sole proprietorship: a general partner or the proprietor, respectively.

Comment on 20.2.50.7(NN)(1): Redline required as NMED already has a definition of responsible official in Part 70. Redline makes definition the same to avoid confusion.

~~**OO. "Small business facility"** means, for the purposes of this Part, a source that is independently owned or operated by a company that is a not a subsidiary or a division of another business, that employs no more than 10 employees at any time during the calendar year, and that has a gross annual revenue of less than $250,000. Employees include part-time, temporary, or limited service workers.~~

Comment on 20.2.50.7(OO): Redline recommended as NMOGA has evaluated the Small Business Facility section and concluded that there is no operator in NM small enough to qualify.

OO. "Stabilized" when used to refer to stored condensate, means that the condensate has reached substantial equilibrium with the atmosphere and that any emissions that occur are those commonly referred to within the industry as "working and breathing losses"

Comment on 20.2.50.7(OO): Redline required to provide definition of stabilized, as storage vessels containing stabilized hydrocarbon liquid may be floating roof or other type of storage vessel and are not subject to requirements for closed vent systems similar to Colorado Regulation 7.

PP. "Startup" means the setting into operation of air pollution control equipment or process equipment.

QQ. "Stationary Source" or **"source"** means any building, structure, equipment, facility, installation (including temporary installations), operation, process, or portable stationary source that emits or may emit any air contaminant. Portable stationary source means a source that can be relocated to another operating site with limited dismantling and reassembly.

RR. "Storage vessel" means a single tank or other vessel that is designed to contain an accumulation of hydrocarbon liquid or produced water and is constructed primarily of non-earthen material including wood, concrete, steel, fiberglass, or plastic, which provide structural support, or a process vessel such as a surge control vessel, bottom receiver, or knockout vessel. A well completion vessel that receives recovered liquid from a well after commencement of operation for a period that exceeds 60 days is considered a storage vessel. A storage vessel does not include a vessel that is skid-mounted or permanently attached to a mobile source and located at the site for less than 180 consecutive days, such as a truck or railcar, or a pressure vessel designed to operate in excess of 204.9 kilopascals (29.724 psi) without emissions to the atmosphere. A storage vessel does not include a storage vessel located at a saltwater disposal facility unless the storage vessel is associated with a produced water management unit.

Comment on 20.2.50.7(RR). Redline required to clarify that tanks at saltwater disposal facilities are not subject to the standard unless the vessel is associated with produced water management units. Tanks at saltwater disposal facilities that are not associated with produced water management units contain liquids consisting of water with insignificant amounts of stabilized skim oil that is not in vapor state at normal or elevated conditions, making regulation of such units unnecessary.

SS. "Tank battery" means a storage vessel or group of storage vessels that receive or store crude oil, condensate, or produced water from a well or wells for storage prior to shipment. This does not include storage vessels at saltwater disposal facilities unless associated with produced water management units.

Comment on 20.2.50.7(SS). Redline required to define tank battery, a term used throughout the rule but not defined. The definition also clarifies that tanks associated with saltwater disposal facilities are not subject to the standard unless the vessel is associated with produced water management units. Tanks at saltwater disposal facilities that are not associated with produced water management units contain liquids consisting of water with insignificant amounts of stabilized skim oil that is not in vapor state at normal or elevated conditions, making regulation of such units unnecessary. This definition also makes clear that tank batteries are those located within the production sector – i.e., those associated with and receiving liquids from wells in the production segment.

TT. "Vapor Recovery Control Unit" means a system composed of a scrubber, a compressor and a switch. Its main purpose is to recover vapors. The switch detects pressure variations and turns the compressor on and off. The vapors are drawn through a scrubber, where entrained liquids are captured and returned to the liquid pipeline system or to a storage vessel, and the vapor recovered is compressed into a sales pipeline or other process. To determine if this device is a vapor recovery unit (process) or a vapor recovery control unit (control) the operator must answer the following three questions:

(1). Is the primary purpose of the equipment to control air pollution?

(2). Where the equipment is recovering product, how do the cost savings from the product recovery compare to the cost of the equipment?

(3). Would the equipment be installed if no air quality regulations are in place?

If the primary purpose is to control air pollution then the device is a vapor recovery control unit. Such device's classification as a control or process unit in a final permit is binding upon both the Department and the operator.

Comment on 20.2.50.7(TT): Redline required as vapor recovery units may be process units or air pollution control equipment. Both EPA and NMED's Air Quality Bureau have recognized this "dual" role of vapor recovery units and have used the "three questions" test and economic analysis to determine how such units should be classified. This definition recognizes the historic tests used by EPA and NMED for when a vapor recovery unit is a piece of air pollution control equipment. Because of the complexity of the test, NMOGA believes that the status of vapor recovery units should be resolved in an appropriate permit proceeding, which would look at the facts and circumstances of each unit, and reach the most appropriate conclusion that would thereafter bind the operator.

UU~~SS~~. "Well workover" means the repair or stimulation of an existing production well for the purpose of restoring, prolonging, or enhancing the production of hydrocarbons.

~~UU~~VV. "~~Wellhead site~~Well Production Facility" means the equipment directly associated with one or more oil wells or natural gas wells upstream of the natural gas processing plant. A well~~head site~~ production facility may include equipment used for extraction, collection, routing, storage (e.g., tank battery), separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and product piping.

Comment on 20.2.50.7(VV): Redline required because the "wellhead" site may not include any equipment, whereas well production facility is more encompassing of the requirements of this Part.

[20.2.50.7 NMAC - N, XX/XX/2021]

20.2.50.8 SEVERABILITY: If any provision of this Part, or the application of this provision to any person or circumstance is held invalid, the remainder of this Part, or the application of this provision to any person or circumstance other than those as to which it is held invalid, shall not be affected thereby.
[20.2.50.8 NMAC - N, XX/XX/2021]

20.2.50.9 CONSTRUCTION: This Part shall be liberally construed to carry out its purpose.
[20.2.50.9 NMAC - N, XX/XX/2021]

20.2.50.10 SAVINGS CLAUSE: Repeal or supersession of prior versions of this Part shall not affect administrative or judicial action initiated under those prior versions.
[20.2.50.10 NMAC - N, XX/XX/2021]

20.2.50.11 COMPLIANCE WITH OTHER REGULATIONS: Compliance with this Part does not relieve a person from the responsibility to comply with other applicable federal, state, or local laws, rules or regulations, including more stringent controls.
[20.2.50.11 NMAC - N, XX/XX/2021]

20.2.50.12 DOCUMENTS: Documents incorporated and cited in this Part may be viewed at the New Mexico environment department, air quality bureau.
[20.2.50.12 NMAC - N, XX/XX/2021]
[The Air Quality Bureau is located at 525 Camino de los Marquez, Suite 1, Santa Fe, New Mexico 87505.]

20.2.23.13-20.2.23.110 [RESERVED]

20.2.50.111 APPLICABILITY:

A. This Part applies to certain crude oil and natural gas production, and processing equipment ~~and~~associated with operations that extract, collect, separate, dehydrate, store, process, transport, transmit, or handle hydrocarbon liquids or produced water in the areas specified in 20.2.50.2 NMAC and are located at well production facility~~wellhead sites~~, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations, up to the point of the local distribution company custody transfer station. Part 50 applies only in areas of the State specified in 20.2.50.2 NMAC

B. In determining if any ~~source~~ unit is subject to this Part, ~~including a small business facility as defined in this Part,~~ the owner or operator shall calculate the Potential to Emit (PTE) of such unit ~~source~~ as necessary. ~~and shall have the PTE calculation certified by a qualified professional engineer.~~ The calculation shall be kept on file for a minimum of five years and shall be provided to the department upon request.

C. ~~An owner or operator of a small business facility as defined in this Part shall comply with the requirements of this Part as specified in 20.2.50.125 NMAC.~~

D. Oil refineries~~y~~ and oil transmission pipelines are not subject to this Part.
[20.2.50.111 NMAC - N, XX/XX/2021]

Comment on 20.2.50.111(B): Redline required to address two concerns. First, not all sections of this Part require calculation of PTE. Thus, we have included the term "as necessary" to reflect that not all applicability thresholds under this Part are based on PTE. Second, it is not appropriate to require a qualified professional engineer to complete the PTE calculation. Many companies have engineers, air quality specialists, or other staff that conduct these PTE analyses, and they may not meet the definition of a qualified engineer. This would require duplicative processes and may create significant concerns with the current qualifications of many of the individuals currently conducting these evaluations. There is no basis for requiring a certification by a qualified professional engineer. PTE is typically calculated based on reasonably accepted methodologies and does not require such a certification.
Furthermore, per the State of New Mexico Board of Licensure for Professional Engineers and Professional Surveyors, "An engineer employed by a business entity who performs only the engineering services involved in the operation of the business entity's business shall be exempt from the provisions of the Engineering and Surveying Practice Act; provided that neither the employee nor the business entity offers engineering services to the public" (Section 61-23-22 of the NM Engineering and Survey Practice Act). In other words, even the state licensing board for professional engineers in the State of New Mexico does not require a professional engineer complete this type of calculation.

20.2.50.112 GENERAL PROVISIONS:

A. General requirements:

(1) Units ~~Sources~~ subject to emissions standards and requirements under this Part shall be operated and maintained consistent with manufacturer specifications, or~~and~~ good ~~engineering~~ operational and maintenance practices, which terms, when used in this Part, mean the original equipment manufacturer (or successor) emissions-related design specifications, maintenance practices and schedules or an alternative set of specifications, maintenance practices and schedules ~~. The owner or operator shall keep manufacturer specifications and maintenance practices on file and make them available upon request by the department. For sources constructed prior to 1980 for which no manufacturer specifications and maintenance practices are available, the owner or operator shall develop and follow a maintenance schedule~~ sufficient to operate and maintain such units in good working order approved by qualified maintenance personnel based upon engineering principles and field experience.. The owner or operator shall keep such manufacturer specifications, or alternative specifications, ~~maintenance schedules~~ whichever are being followed, on file and make them available to the department upon request. The terms of this 20.2.50.112.A(1) NMAC apply any time reference to manufacturer specifications occurs in this Part.

Comment on 20.2.50.112(A)(1): Redline required as document changed to distinguish between "source" to "unit" throughout where appropriate. As written, the rule conflates stationary sources and sources (i.e., specific units subject to the rule). NMOGA proposes to use "source" when it refers to the stationary source or facility itself and "unit" when it refers to the specific affected/regulated equipment. In addition, with respect to the above, manufacturer specifications are not always appropriate for following either because (1) they are not developed or designed for the purposes of minimizing emissions, (2) owners and operators have developed their own specific practices for those sources, which should be deferred to; or (3) full compliance with manufacturer specifications simply encourages manufacturers to require more testing/maintenance (to the benefit of the manufacturing company).
Redline required as owners and operators may not have a complete set of manufacturer specifications, particularly for older equipment or equipment obtained during acquisitions. Additionally, original manufacturer specifications may not be relevant if the units are modified in the field or the original specifications are inadequate to maintain field reliability. Accordingly, the term "manufacturer specifications" should include similar specifications, maintenance practices and schedules developed by qualified personnel, when the original specifications are not available, not relevant due to modifications, or have been found inadequate or inappropriate based upon operator's experience. NMOGA agrees that these specifications should be available to the department upon request.

(2) Units ~~Sources~~ , including associated air pollution control equipment and monitoring equipment, subject to emission standards or requirements under this Part shall at all times, including periods of startup, shutdown, and malfunction, be operated and maintained in a manner consistent with safety and good air pollution control practices for ~~to~~ minimizinge~~e~~ emissions of ~~air contaminants, including~~ VOC and NOx. During a period of startup, shutdown, or malfunction, this general duty to minimize emissions requires that the owner or operator reduce emissions from the affected unit to the greatest extent which is consistent with safety and good air pollution control practices. The general duty to minimize emissions does not require the owner or operator to make any further efforts to reduce emissions if levels required by the applicable standard have been achieved. The terms of this 20.2.50.112.A(2) apply any time reference to minimizing emissions occurs in this Part.

Comment on 20.2.50.112(A)(2): Redline required as NMOGA believes that the general duty clause is best located in the general provisions rather than appearing repetitively throughout the rule. NMOGA believes that NMED should follow the model established by EPA in the NESHAP program and adopted by reference by the EIB in 20.2.82.9 NMAC, which incorporates language from 40 CFR 63.6(e)(1)(i). NMOGA has cleaned the language up to eliminate some of the startup, shutdown and malfunction language which is currently in flux. The federal language, as cleaned up to minimize SSM conflicts, represents a good resolution of this issue that was reached after extensive notice and comment.

(3) Within two years of the effective date of this Part, owners and operators of a ~~source~~unit requiring ~~an~~ ~~E~~equipment ~~Monitoring~~monitoring, testing, or inspection ~~Tag (EMT)~~ will develop and implement database system(s) capable of storing information for each unit in a manner consistent with this section. ~~shall physically tag each unit with an EMT, the format of which shall be either RFID, QR, or bar code such that, when scanned it provides a unique identifier of the source. This unique identifier shall act as an index to the source's record of the data required by this Part.~~ The owner or operator shall maintain information regarding each unit requiring equipment monitoring, testing, or inspection in a database system(s), including ~~The EMT shall be maintained by the owner or operator, and data in the EMT shall provide~~ at a minimum, the following information:

(a) unique unit identification number;
(b) location (latitude and longitude) of the source at which the unit is located;
(c) type of ~~source~~ unit (e.g., tank, ~~VRU~~VRCU, dehydrator, pneumatic controller, etc.);
(d) for each source, the VOC (and NO_X, if applicable) PTE in lbs./hr. and tpy;
~~**(e)** for a control device, the controlled VOC and NO_X PTE in lbs./hr. and tpy;~~ **(e~~f~~)** if available, make, model, and serial number; and

(~~f~~g) a link to the manufacturer's maintenance schedule or repair recommendations or company-specific operational and maintenance practices.

(4) The database system(s) ~~EMT~~ shall be ~~installed and~~ maintained by the owner or operator of the facility.

~~(5) The EMT shall be of a format scannable by an owner or operator's authorized required by this Part.~~

(5) The owner or operator shall manage the ~~source's~~ unit's record of data in ~~a~~ the database system(s) and the database system(s) must be ~~that is~~ able to generate a Compliance Database Report (CDR). The CDR is an electronic report generated by the owner or operator's database system(s) and submitted to the department upon request. ~~The format of the CDR shall be determined by the department.~~

(~~7~~6) The CDR is a report distinct from the owner or operator's ~~database~~database system(s). The department does not require access to the owner or operator's database system(s), only the CDR.

(~~8~~7) ~~If read by the o~~Owner or operator's authorized representative must be able to access and input data in the ~~, the EMT shall access the owner or operator's database~~database system(s) record for that unit~~source~~. That access is not required to be at any time from any location.

(~~9~~8) The owner or operator shall ~~contemporaneously~~ track each ~~compliance event~~ monitoring, testing, and inspection events for each ~~source~~ unit subject to the ~~EMT~~ requirements of this Part, and shall comply with the following:

(a) data gathered during each monitoring, testing, or inspection ~~or testing~~ event shall be ~~contemporaneously~~ uploaded into the ~~database~~database system(s) as soon as practicable, but no later than three business days ~~of~~ after each ~~compliance event~~monitoring, testing, or inspection event or when final reports are received.

(b) data required by this Part shall be maintained in the ~~database~~database system(s) for at least five years.

(~~10~~9) Upon demonstration of good cause, t~~T~~he department may request that an owner or operator retain a third party at their own expense to verify any data or information collected, reported, or recorded pursuant to this Part, and make recommendations to correct or improve the collection of data or information. The owner or operator shall submit a report of the verification and any recommendations made by the third party to the department by a date specified and implement the recommendations in the manner approved by the department. The owner or operator may request a hearing on whether good cause was demonstrated or whether the recommendations approved by the department must be implemented.

Comment on 20.2.50.112(A)(3): Redline required as barcode, QR coding, and other tracking devices have been shown to be difficult in implementation. The EMT system is unprecedented in its prescriptiveness and is even more onerous than a system required in an extreme nonattainment area (San Joaquin Valley, CA). The cost of implementation and maintenance of an EMT system will be disproportionately higher than the emission reduction potential. NMOGA member companies can identify no other air quality regulations that have successfully implemented and justified the requirement for a similar system.
At this time, NMOGA has not found a currently available commercial software product suitable for oil and gas operations that will satisfy the proposed EMT system. Having each operator develop a system of such complexity will require tremendous time, cost and effort with the largest burden falling to smaller operators. Tagging devices also presents safety concerns. Some components that would be required to be tagged under this proposal operate at extremely high temperatures or are not readily accessible. Requiring placement and scanning of such tags puts personnel at risk of injury. The language in this rule does not provide a cogent statement of the anticipated environmental benefit of the EMT system, making it difficult for NMOGA to provide cost effective solutions to NMED's environmental concerns.

Comment on 20.2.50.112(A)(3)(a)-(f): Redline required to clarify this section to indicate what is intended by location (i.e., it is the latitude and longitude of the source at which the unit is located). NMOGA also referenced back to operators use of their own company-specific engineering and maintenance practices.

Comment on 20.2.50.112(A)(5): Redline required because format of the CDR is defined in substantive sections of part 50.

Comment on 20.2.50.112(A)(7): Redline required because unreliable electronic connectivity in the field is prevalent and prevents operators from accessing these database system(s) from the field. For this reason, operators need flexibility to enter field data into systems from an office or officelike setting after the field data has been gathered.

B. **~~Monitoring~~Monitoring, testing, or inspection requirements:**

(1) Units ~~Sources~~ subject to emission standards and monitoring, testing or inspection ~~(e.g. inspection, testing, parametric monitoring)~~ requirements under this Part shall be inspected monthly to ensure proper maintenance and operation, unless a different schedule is specified in the Section applicable to that ~~source~~ unit type. If the equipment is shut down at the time of required periodic testing, monitoring, or inspection, the owner or operator shall not be required to restart the unit for the sole purpose of performing the testing, monitoring, or inspection, but shall note the shut down in the records kept for that equipment for that ~~monitoring~~monitoring, testing, or inspection event.

(2) An owner or operator may submit for the department's review and approval ~~an equally effective, enforceable, and equivalent alternative monitoring strategy~~ an enforceable and equivalent alternative monitoring, testing, or inspection strategy. Such requests shall be made on an application form provided by the department. The department shall issue a letter approving or denying the requested alternative ~~monitoring~~monitoring, testing, or inspection strategy. An owner or operator shall comply with the default ~~monitoring~~monitoring, testing, or inspection requirements required under the applicable Section and shall not operate under an alternative ~~monitoring~~monitoring, testing, or inspection strategy until it has been approved by the department.

(3) ~~Each~~ For each monitoring, testing or inspection event ~~(e.g. testing, inspection, parametric monitoring)~~ owners, operators, or their authorized representatives shall ~~be initiated by an initial scanning of the EMT, the results of which shall then be directly uploaded into the database or temporarily into the handheld or other device. Upon completion of the monitoring event, a final scanning of the EMT shall terminate the monitoring event. At a minimum, the uploaded data shall include~~record the information required by the applicable sections of this Part~~:~~

~~**(a)** date and time of the testing, monitoring, or inspection event;~~

~~**(b)** name of the personnel conducting the testing, monitoring, or inspection;~~

~~**(c)** identification number and type of unit;~~

~~**(d)** a description of any maintenance or repair activity conducted; and~~

~~**(e)** results of testing, monitoring, or inspection as required under this Part.~~

Comment on 20.2.50.112(B)(3)(a)-(e): Redline required as the individual sections of this Part specify with more precision what is required for that unit/source or activity.

C. Recordkeeping requirements:

(1) Within three business days of a ~~monitoring~~monitoring, testing, or inspection event or within three business days of when final reports of monitoring, testing or inspection results are received, an electronic record shall be made of the ~~monitoring~~monitoring, testing, or inspection event and shall include ~~the following data~~the information required by the applicable sections of this Part.~~:~~

~~**(a)** date and time of the testing, monitoring, or inspection event;~~

~~**(b)** name of the personnel conducting the testing, monitoring, or inspection;~~

~~**(c)** identification number and type of unit;~~

~~**(d)** a description of any maintenance or repair activity conducted; and~~

~~**(e)** results of any testing, monitoring, or inspections required under this Part.~~

(2) The owner or operator shall keep an electronic record required by this Part for five years. ~~The department may treat loss of data or failure to maintain a record, including failure to transfer a record upon sale or transfer of ownership or operating authority, as a failure to collect the data.~~

~~**(3)** Before the transfer of ownership of equipment subject to this Part, the current owner or operator shall conduct and document a full compliance evaluation of such equipment. The documentation shall include a certification by a responsible official as to whether the equipment is in compliance with the requirements of this Part. The compliance determination shall be conducted no earlier than three months before the transfer of ownership. The owner or operator shall keep the full compliance evaluation and certification by the responsible official for five years.~~

Comment on 20.2.50.112(C)(1): Redline required to accommodate for lead time on third party reports (e.g., stack tests).

Comment on 20.2.50.112(C)(1)(a)-(e): Redline required as the individual sections of this Part specify with more precision what is required for that unit/source or activity. It is confusing for an operator to have to review two sections to understand comprehensively what records it needs to keep for specific equipment.

Comment on 20.2.50.112(C)(3): Redline required NMED has authority to require compliance certifications and to require those to be submitted to the agency as part of its general enforcement powers; however, the agency has no authority to inject air compliance requirements into transactions between third parties. Not only does this requirement interfere with negotiation strategy of a seller, which sometimes may be "as is, where is", it interferes with the sellers ability to negotiate the traditional elements of a sales agreement (representations, warranties, indemnity, etc). It clearly creates a disadvantage for sellers with operations subject to the rule and thus may violate the U.S. Constitution Commerce clause by creating a rule that burdens interstate commerce by requiring operators in limited areas of the state to take an action that may impact the value or salability of their facilities versus operators in other parts of the state or out of state. If owners or operators economically in need of divesting assets cannot sell their facilities to buyers with the means to operate the facilities, sellers may be forced to prematurely shut in an otherwise viable operation, thereby wasting those resources and impacting royalty holders.

Even if this requirement can overcome the potential Constitutional issues, the agency is not considering the complexity and scope of many transactions. Some transactions do not result in a change of operatorship, for example, a Non-Operated Owner under a Joint Operating Agreement may engage in a sale of a partial ownership interest in a given facility. That doesn't constitute a change of operatorship of the equipment because the Operator will still operate that equipment under the Joint Operating Agreement. It's not uncommon for oil and gas transactions to involve a sale of an entire field with 1000s of facilities in a short period of time where requiring this certification could be very difficult given the time frame outlined. As a result, the time frame could unnecessarily delay or ultimately prevent a transaction from occurring. Further, the three months before transfer of ownership is also problematic since many transactions include a two-step signing and closing process, the first to enter into an agreement to sell, followed by a closing and formal interest conveyance that may be months later. During this time, the seller continues to own and/or operate the assets while negotiations continue. Introducing a compliance evaluation at or near the end of a transaction process may upset months of negotiation. It is also unclear how the proposed certification requirement would work in conjunction with the compulsory pooling process, which include operatorship over defined development activities and associated facilities, but not the ownership of such facilities. Finally, this requirement has no reasonable relationship to the statutory requirement to regulate sources in areas that exceed 95% of the ozone NAAQS and it does not meet the statutory criteria to be more stringent than federal standard. EPA has no such regulations and this interference in an arms-length negotiation has no relationship to protecting public health and the environment.

D. **Reporting requirements:** Within ~~24 hours~~three business days of a request by the department, the owner or Operator shall for each unit subject to the request, provide the requested information ~~either by~~ electronically submitting a CDR to the department's Secure Extranet Portal (SEP), or by other means and formats specified by the department in its request. If the department requests CDR from multiple facilities, additional time shall be given as appropriate.

Comment on 20.2.50.112(D): Redline required as 24 hours is not reasonable. NMED air permits specify that data must be provided within 3 business days from the request, and that has been workable. Unexpected circumstances may also warrant an extension and that option should be made available.

[20.2.50.112 NMAC - N, XX/XX/2021]

20.2.50.113 **ENGINES AND TURBINES:**

A. **Applicability:** Portable and stationary natural gas-fired spark ignition engines, compression ignition engines, and natural gas-fired combustion turbines located at ~~wellhead sites~~well production facility, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations, with a site-rated horsepower greater than the horsepower ratings of Table 1, 2, and 3 of 20.2.50.113 NMAC are subject to the requirements of 20.2.50.113 NMAC. Non-road engines as defined in 40 C.F.R. 1068.30 are not subject to 20.2.50.113 NMAC.

Comment on 20.2.50.113(A): Redline required to remove non-road engines from the scope of the rule. Under 42 U.S.C. § 7543(e)(1), Congress expressly preempted states from adopting or attempting to enforce any standard or other requirement relating to the control of emissions from (1) new nonroad engines used in construction/farm equipment or nonroad vehicles with less than 175 horsepower, or (2) new locomotives or new nonroad engines used in locomotives. 42 U.S.C. § 7543(e)(1). For any new or used nonroad engine or vehicle not addressed in § 7543(e)(1), Congress granted California exclusive authority to adopt standards and other requirements for the control of emissions. 42 U.S.C. § 7543(e)(2)(A). States other than California may promulgate such standards only if the effective date is delayed for 2 years and the emission standards are identical to provisions adopted by California through the statutorily-prescribed process. 42 U.S.C. § 7543(e)(2)(B). It is not enough that state standards are equally protective or substantially similar; they must be identical. Id. By expressly granting California exclusive authority to establish nonroad engine standards, Congress impliedly preempted any state other than California from adopting such standards for nonroad engines and vehicles within the scope of § 7543(e)(2). Engine Mfrs. Ass'n v. U.S. E.P.A., 88 F.3d 1075, 1087-88 (D.C. Cir. 1996) ("states must be preempted from adopting any regulation for which California could receive authorization."); Pac. Merch. Shipping Ass'n v. Goldstene, 517 F.3d 1108, 1113 (9th Cir. 2008) ("we join the D.C. Circuit and hold that the implied preemption of § 209(e)(2) applies to 'any nonroad vehicles or engines,' including new and non-new sources."). New Mexico's proposed standards are not identical to non-road engine standards adopted by California and are therefore preempted under 42 U.S.C. 7543(e).

B. **Emission standards:**

(1) The owner or operator of a portable or stationary natural gas-fired spark-ignition engine, compression ignition engine, or natural gas-fired combustion turbine shall ensure compliance with the emission standards by the dates specified in Subsection B of 20.2.50.113 NMAC or engines that are subject may comply with the requirements through an alternative Compliance Plan of 20.2.50.113 B.10.

(2) The owner or operator of an existing natural gas-fired spark-ignition engine shall complete an inventory of all existing engines subject to this Part 50 by January 1, 2023, and shall prepare a schedule to ensure that each existing engine does not exceed the emission standards in table 1 of Paragraph (2) of Subsection B of 20.2.50.113 NMAC except as approved through an alternative Compliance Plan per 20.2.50.113 B.10. as follows:

Comment on 20.2.50.113.B(1)-(2). Redlined required to allow use of an alternative compliance plan as detailed further in comments to 20.2.50.113.B(10).

(a) by January 1, 2025, the owner or operator shall ensure at least thirty percent of the company's existing engines meet the emission standards.

(b) by January 1, 2027, the owner or operator shall ensure at least an additional thirty-five percent of the company's existing engines meets the emission standards.

(c) by January 1, 2029, the owner or operator shall ensure that the remaining thirty-five percent of the company's existing engines meets the emission standards.

(d) in lieu of meeting the emission standards for an existing natural gas-fired spark ignition engine, an owner or operator may reduce the annual hours of operation of an engine such that the annual PTE for NOx and VOC emissions are reduced to achieve an equivalent allowable ton per year emission as set forth in Table 1 of Paragraph (2) of Subsection B of 20.2.50.113 NMAC or by at least ninety-five percent per year.

(e) Owners or operators of an existing natural gas-fired spark-ignition engine are not required to comply with the emissions standards specified in table 1 of Subsection B of 20.2.30.113 NMAC if the owner or operator demonstrates that the emissions standard is technically impractical or economically unreasonable. Installation and maintenance costs and the best information available for determining technically practicable retrofit technology and control efficiency shall be considered. Owners or operators that seek to rely on this exemption must submit a justification for the technical impracticality or economic unreasonableness to the department for approval no less than ninety (90) days prior to the applicable compliance date set forth in the schedule in Paragraph (2) of Subsection B of 20.2.50.113 NMAC. If the department does not respond to the justification within forty-five (45) days after submission of the justification, the justification will be deemed approved.

(f) Any of the effective dates for the emissions standards set forth in Paragraph (2) of Subsection B of 20.2.50.113 NMAC may be extended at the Department's discretion for good cause shown.

Table 1 - EMISSION STANDARDS FOR NATURAL GAS-FIRED SPARK-IGNITION ENGINES CONSTRUCTED OR~~,~~ RECONSTRUCTED~~, OR INSTALLED~~ BEFORE THE EFFECTIVE DATE OF 20.2.50 NMAC.

~~Engine Type~~	~~Rated bhp~~	~~NO_x~~	~~CO~~	~~NMNEHC (as propane)~~
~~Lean-burn~~	~~>1,000~~	~~0.50 g/bhp-hr~~	~~47 ppmvd @ 15% O2 or 93% reduction~~	~~0.70 g/bhp-hr~~
~~Rich-burn~~	~~>1,000~~	~~0.50 g/bhp-hr~~	~~0.60 g/bhp-hr~~	~~0.70 g/bhp-hr~~

Maximum Engine BHP	Emission Standards (g/bhp-hr)		
	NOx	CO	VOC
4 Stroke ~~All~~ Lean Burn engines >1000 bhp (4-stroke)	2.0	2.0	0.7
2-Stroke Lean Burns* >1000 bhp	3.0	2.0	0.7
All Rich Burn engines > 1000 bph	0.5	0.6	0.7

Comment on 20.2.50.113(B)(2)(d): Redline required as this hours reduction should be based on the number of hours that would result in an equivalent amount of reduction to the existing emissions limit, and not 95%. Asking for reductions by 95% even if an operator is currently operating near the emissions standard would require further reductions than set forth in Table 1 and is unreasonable.

Comment on 20.2.50.113(B)(2)(e): Redline required to include an opportunity for exemption based on either technical feasibility or economic reasonableness for any given individual engine. For transmission assets for example, it cannot simply limit operation of a unit and not provide natural gas to customers, and there may be no technically feasible or economically

reasonable way to otherwise achieve an emission standard.
Redline required because a defined timeframe is necessary such that department can respond so that is it not open-ended request. This will ensure that operators can receive a resolution without waiting in perpetuity.

Comment on 20.2.50.113(B)(2)(f), Table 1: Redline required: Constructed and installed are redundant with current construction definition. Installation of an engine should not trigger the requirements for new engines.
Construction definition per NESHAP: Construction means the on-site fabrication, erection, or installation of an affected source. Construction does not include the removal of all equipment comprising an affected source from an existing location and reinstallation of such equipment at a new location. The owner or operator of an existing affected source that is relocated may elect not to reinstall minor ancillary equipment including, but not limited to, piping, ductwork, and valves. However, removal and reinstallation of an affected source will be construed as reconstruction if it satisfies the criteria for reconstruction as defined in this section. The costs of replacing minor ancillary equipment must be considered in determining whether the existing affected source is reconstructed.
2-Stroke Lean Burn > 1000 bhp, Reference Colo 5-CCR-1001-9 Part E, Table 2.
Reference Colo 5-CCR-1001-9 Part E, Table 1, as applicable to 20.2.50 NMAC (JJJJ).

(3) The owner or operator of a new natural gas-fired spark ignition engine shall ensure the engine does not exceed the emission standards in table 2 of Paragraph (3) of Subsection B of 20.2.50.113 NMAC upon startup.

Table 2 - EMISSION STANDARDS FOR NATURAL GAS-FIRED SPARK-IGNITION ENGINES CONSTRUCTED OR~~,~~ RECONSTRUCTED, ~~OR INSTALLED~~ AFTER THE EFFECTIVE DATE OF 20.2.50 NMAC.

~~Engine Type~~	~~Rated bhp~~	~~NO_x~~	~~NMNEHC (as propane)~~
~~4 Stroke Lean-burn~~	~~>500 - <1,000~~	~~0.50 g/bhp-hr~~	~~0.70 g/bhp-hr~~
~~4 Stroke Lean-burn~~	~~≥1,000~~	~~0.30 g/bhp-hr uncontrolled or 0.05 g/bhp-hr with NOx control post-combustion~~	~~0.70 g/bhp-hr~~
~~4 Stroke Rich-burn~~	~~>500~~	~~0.50 g/bhp-hr~~	~~0.70 g/bhp-hr~~

Engine Type	Engine (bhp)	Emissions (g/bhp-hr)		
		NOx	CO	VOC
4-Stroke Lean Burn engines	>1000 bhp and < 2370	0.7	2.0	0.7
4-Stroke Rich Burn engines	>1000 bhp and < 2370	0.5	2.0	0.7
All engines	≥2370 bhp	0.3	2.0	0.7

Comment on 20.2.50.113(B)(3), Table 2: Redline required: 0.30 g/bhp-hr will effectively eliminate an entire product offering from Caterpillar, 3500 series engines (~1000-1800hp). Right now, there are effectively two engine manufacturer choices in this space, Waukesha and Caterpillar.
All emission and hp levels should ensure that product offerings are available from at least 2 engine viable/traditional options (e.g., an obscure manufacturer not traditionally in O&G space would not be considered. Caterpillar and Waukesha are the primary engine manufactures in the oil and gas space).
Reference Valor Memo - Engines and Turbines 20.2.50.113.

(4) The owner or operator of a natural gas-fired spark ignition engine with NOx emission control technology that uses ammonia or urea as a reagent shall ensure that the exhaust ammonia slip is limited to 10 ppmvd or less, corrected to fifteen percent oxygen.

(5) The owner or operator of a compression ignition engine shall ensure compliance with the following emission standards:

(a) a new portable or stationary compression ignition engine with a maximum design power output equal to or greater than 500 horsepower that is not subject to the emission standards under Subparagraph (b) of Paragraph (5) of Subsection B of 20.2.50.113 NMAC shall limit NOx emissions to not more than nine g/bhp-hr upon startup.

(b) a stationary compression ignition engine that is subject to and complying with Subpart IIII of 40 CFR Part 60, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, is not subject to the requirements of Subparagraph (a) of Paragraph (5) of Subsection B of 20.2.50.113 NMAC.

(6) The owner or operator of a portable or stationary compression ignition engine with NO_x emission control technology that uses ammonia or urea as a reagent shall ensure that the exhaust ammonia slip is limited to 10 ppmvd or less, corrected to fifteen percent oxygen.

(7) The owner or operator of a stationary natural gas-fired combustion turbine with a maximum design rating equal to or greater than 1,000 bhp shall comply with the applicable emission standards for an existing, new, or reconstructed turbine listed in table 3 of Paragraph (7) of Subsection B of 20.2.50.113 NMAC.

(a) The owner or operator of an existing stationary natural gas-fired combustion turbine shall complete an inventory of all existing turbines subject to this Part 50 by July 1, 2022, and shall prepare a schedule to ensure that each subject existing turbine does not exceed the emission standards in table 3 of Paragraph (7) of Subsection B of 20.2.50.113 NMAC except as approved through an alternative Compliance Plan per 20.2.50.113 B.9 as follows:

(i) by January 1, 20245, the owner or operator shall ensure at least thirty percent of the company's existing turbines meet the emission standards.

(ii) by January 1, 2027~~6~~, the owner or operator shall ensure at least an additional thirty-five percent of the company's existing turbines meets the emission standards.

(iii) by January 1, 2029~~8~~, the owner or operator shall ensure that the remaining thirty-five percent of the company's existing turbines meets the emission standards.

(iv) in lieu of meeting the emission standards for an existing stationary natural gas-fired combustion turbine, an owner or operator may reduce the annual hours of operation of a turbine such that the annual PTE for NOx and VOC emissions are reduced to achieve an equivalent ton per year emission reduction as set forth in table 3 of Paragraph (7) of Subsection B of 20.2.50.113 NMAC or by at least ninety-five percent per year.

(v) Owners or operators of an existing natural gas-fired combustion turbine are not required to comply with the emissions standards specified in table 3 of Subsection B of 20.2.30.113 NMAC if the owner or operator demonstrates that the emissions standard is technically impractical or economically unreasonable. Installation and maintenance costs and the best information available for determining technically practicable retrofit technology and control efficiency shall be considered. Owners or operators that seek to rely on this exemption must submit a justification for the technical impracticality or economic unreasonableness to the department for approval no less than ninety (90) days prior to the applicable compliance date set forth in the schedule in Paragraph (7)(a) of Subsection B of 20.2.50.113 NMAC. If the department does not respond to the justification within forty-five (45) days after submission of the justification, the justification will be deemed approved.

(vi) Any of the effective dates for the emissions standards set forth in Paragraph (7) of Subsection B of 20.2.50.113 NMAC may be extended at the Department's discretion for good cause shown.

Comment on 20.2.50.113(B)(7)(a): Redline required as it is absolutely necessary that a similarly staggered schedule be set for existing turbines as for existing engines. The modifications necessary to achieve the thresholds are equally as significant, custom, costly, and time-intensive. Compared to engines, the same number of emission units, if not more, are impacted. NMOGA members have contacted suppliers and received estimated delivery dates stretching into 2028 for possible delivery so the January 1, 2028 deadline is not feasible.

Comment on 20.2.50.113(B)(7)(a)(v): Redline required to include an opportunity for exemption based on either technical feasibility or economic reasonableness for any given individual engine. For transmission assets for example, it cannot simply limit operation of a unit and not provide natural gas to customers, and there may be no technically feasible or economically reasonable way to otherwise achieve emission standard.
Redline required because a defined timeframe is necessary such that department can respond so that is it not an open-ended request. This will ensure that operators can receive a resolution without waiting in perpetuity.

Table 3 - EMISSION STANDARDS FOR STATIONARY COMBUSTION TURBINES

For each applicable natural gas-fired combustion turbine constructed or reconstructed ~~and installed~~ before theeffective date of 20.2.50 NMAC, the owner or operator shall ensure the turbine does not exceed the following emission standards no later than the schedule set forth in Paragraph (7)(a) of Subsection B of 20.2.50.113 NMAC~~two years from the effective date of this Part~~:			
Turbine Rating (bhp)	NO_x (ppmvd @15% O_2)	~~CO (ppmvd @ 15% O_2)~~	NMNEHC (as propane, ppmvd @15% O_2)
≥~~1,~~4,000 and <5,000	50	~~50~~	9

≥5,000 and <15,000	50	~~50~~	9
≥15,000	50	~~50 or 93% reduction~~	5 or 50% reduction

For each natural gas-fired combustion turbine constructed or reconstructed ~~and installed~~ on or after the effective date of 20.2.50 NMAC, the owner or operator shall ensure the turbine does not exceed the following emission standards upon startup:			
Turbine Rating (bhp)	NO_x (ppmvd @15% O_2)	~~CO (ppmvd @ 15% O2)~~	NMNEHC (as propane, ppmvd @15% O_2)
≥4~~1~~,000 and <5,000	25	~~25~~	9
≥5,000 and <15,900	15	~~10~~	9
≥15,900	9.0 Uncontrolled ~~or 2.0 with NOx cControl post-combustion~~	~~10 Uncontrolled or 1.8 with Control~~	5

Comment on 20.2.50.113(B)(7), Table 3, Part 1: Reference Valor Memo - Engines and Turbines 20.2.50.113.
Redline required as CO is not an ozone precursor.
Redline required as SCR is the only available option to achieve 50 ppmvd thresholds on these smaller units. The cost of putting SCR on a unit between 1,000 and 4,000 bhp is unreasonable at approximately $108,000/ton. This is categorically economically infeasible. In lieu of the 50 ppmvd, NMOGA recommends that the rule follow 40 CFR 60 KKKK.
Redline required as New Mexico has many existing turbines in the smallest category that will be unable to meet the proposed standard without add-on control. A higher emissions level, congruent with Subpart KKKK, will allow for DLN where it's available to be retrofit and allow the smaller turbines, for which DLN in not available, to continue to operate. Many, if not all, of the turbines that fall into this smallest category are Subpart GG (or pre-NSPS) turbines.

Sections 20.2.50.2 and 20.2.50.7 clearly state that the scope and objective of the Part is to establish emissions standards for ozone precursors, volatile organic compounds (VOC) and nitrogen oxides (NOx), in specific counties. As such, including emission standards, monitoring, recordkeeping, reporting, and testing requirements for CO should not be included in the rulemaking. In the event that NMED does not remove all references to CO in this proposed ozone rule, a level of 50 ppm for existing sources should be established.

Comment on 20.2.50.113(B)(7), Table 3, Part 2: Redline required: Per the NOx standards proposed in the other size categories, the intent of the proposed NMED rule is for compliance to be achieved with dry low NOx combustion retrofits. The 25ppm NOx level is not an appropriate standard for the 1000 to 5000 hp turbine category.
NMED modeled the proposed ozone rule after Pennsylvania's GP-5 rule but did not adopt all of the applicability language with respect to existing sources. GP-5 does not impact pre-2013 units. In GP-5, units constructed on or after February 1, 2013, but prior to August 8, 2018 have to meet either 25 or 15 ppm NOx depending on their size. The NMED proposed rule impacts all existing units with no consideration for date of construction. Further background on the GP-5 rule development process is that there were no turbines in Pennsylvania in the 1000-5000 hp range installed on or after February 1, 2013, but prior to August 8, 2018 so no existing units were affected. As such, it did not come to light that the NOx emission standards in this size category are not technically achievable or commercially available from turbine manufacturers. Add-on control, specifically selective catalytic reduction, would be necessary to achieve the proposed standards on many vintage turbine units which do not have DLN (dry low NOx) capabilities.
Reference Valor Memo - Engines and Turbines 20.2.50.113.

(8) The owner or operator of a stationary natural gas-fired combustion turbine with NO_x emission control technology that uses ammonia or urea as a reagent shall ensure that the exhaust ammonia slip is limited to 10 ppmvd or less, corrected to fifteen percent oxygen.

(~~(9) The owner or operator of an engine or turbine shall install an EMT on the engine or turbine in accordance with 20.2.50.112 NMAC.~~

~~10~~(9) The owner or operator of an emergency use engine as defined by 40 C.F.R. §§ 60.4211, 60.4243, or 63.6675~~that is operated less than 100 hours per year~~ is not subject to the emissions standards in this Part but shall be equipped with a non-resettable hour meter to monitor and record any hours of operation.

Comment on 20.2.50.113(B)(9): Redline required because, by definition, emergency engines are allowed to operate more than 100 hours in the case of an emergency. The 100 hours is the limit on maintenance/testing (i.e., non-emergency use). Based on size/use of these units, emergency engines must be exempt from this Part 50. We think this was NMED's intent and this revision aims to clarify.

(10) An owner or operator may elect to comply with the standards established in 20.2.50.113.B through development and implementation of an Alternative Compliance Plan approved by the Department instead of achieving the standards established in 20.2.50.113.B for each engine or turbine. The Alternative Compliance Plan must include the list of engines or turbines subject to the standards included in the plan and must include a demonstration that the total allowable regulated emissions under the Alternative Compliance Plan do not exceed the total allowable regulated emissions allowed under the emissions standards of this Part and that the owner or operator will achieve emissions under the Alternative Compliance Plan consistent with the schedules set forth in this Part. The department must approve an Alternative Compliance Plan that meets this condition unless the Division identifies that the total allowable emissions allowed under the Alternative Compliance Plan do not meet or are not less than the total allowable emissions under the emissions standards of this Part.

Comment on 20.2.50.113(B)(10) (added): Redlined required to allow owners and operators flexibility in achieving the emissions reductions required by the rule. As detailed elsewhere, NMOGA has serious concerns about the technical and economic feasibility of this rule, particularly when the reductions are applied on a per-engine basis. By allowing owners and operators to achieve the emissions reductions on a total allowable regulated emissions basis, owners and operators will be able to achieve the same environmental benefits without incurring unnecessary costs.

(11) A short term replacement engine may be substituted for any engine regulated under 20.2.50.113 consistent with any applicable air quality permit containing allowances for short term replacement engines, including, but not limited to, New Source Review and General Construction Permits issued under 20.2.72 NMAC. A short term engine replacement is not considered a "new" engine for purposes of 20.2.50 NMAC, unless the engine it replaces is a "new" engine within the meaning of 20.2.50 NMAC. The reinstallation of the existing engine after removal of the short replacement engine is not considered a "new" engine under 20.2.50.113 unless the engine was "new" prior to the temporary replacement.

Comment on 20.2.50.113.B(11). Redline required to allow use of short term replacement engines consistent with existing allowances in NMED's general oil and gas permit and NSR permit standard conditions. Engines need to be taken out of service from time to time for maintenance or repair, and operators need flexibility to use replacement engines to continue operations. NMOGA is concerned that this routine activity may subject replacement of existing engines to "new" emissions standards based on NMED's broad definition of construction. NMOGA does not believe NMED intends this outcome and has added this provision to address this concern.

C. Monitoring, testing, and inspection requirements:

(1) Maintenance and repair for a spark-ignition engine, compression-ignition engine, and stationary combustion turbine shall be consistent with -manufacturer specifications as stated in 20.2.50.112 NMAC. Maintenance consistent with an applicable NSPS or NESHAP standard shall be deemed compliance with 29.2.50.113.C(1). ~~meet the minimum manufacturer recommended maintenance schedule. The following maintenance, adjustment, replacement, or repair events for engines and turbines shall be documented as they occur:~~

~~**(a)** routine maintenance that takes a unit out of service for more than two hours during any 24-hour period; and~~

~~**(b)** unscheduled repairs that require a unit to be taken out of service for more than two hours during any 24-hour period.~~

Comment on 20.2.50.113(C)(1): Redline required to substitute defined term from section 20.2.50.112 as operators have developed their own maintenance schedules, in particular for older engines, where manufacturer recommendations may not be available or are outdated. Compliance with NSPS and NESHAP standards should also be sufficient to demonstrate proper maintenance.

Comment on 20.2.50.113(C)(1)(a)-(b): Redline required as these subparts are recordkeeping requirements, not monitoring requirements. Recordkeeping related to maintenance activities are discussed in the Recordkeeping section.

(2) Catalytic converters (oxidative, selective and non-selective) and AFR controllers shall be maintained according to manufacturer specifications as stated in 20.2.50.112 NMAC ~~or supplier recommended maintenance schedules,~~

~~including replacement of oxygen sensors as necessary for oxygen-based controllers~~. During periods of catalytic converter or AFR controller maintenance, the owner or operator shall shut down the engine or turbine until the catalytic converter or AFR controller can be replaced with a functionally equivalent spare to allow the engine or turbine to return to operation.

(3) For equipment operated for 500 hours per year or more, compliance with the emission ~~-~~standards in Subsection B of 20.2.50.113 NMAC shall be demonstrated ~~performing an initial emissions test, followed by annual tests, for NOx, CO, and non-methane non-ethane hydrocarbons (NMNEHC) using a portable 27 analyzer or U.S. EPA reference method.~~ within 180 days of the effective date applicable to the unit as defined by Subsection B (2) and (7) or, if installed more than 180 days after the effective date, within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after initial startup of such unit. Compliance with the applicable emission standards shall be demonstrated by performing an initial emissions test for NOx and VOCs, as defined in 40 CFR 51.100(s) using U.S. EPA Reference Methods or ASTM D6348. Periodic monitoring demonstrating compliance with the allowable emission limits shall be conducted annually and may be demonstrated utilizing a portable analyzer or EPA Reference Methods. For units with g/hp-hr emission standards, the engine load shall be calculated using the following equations or other alternative methods:

$$\text{Load (Hp)} = \frac{\text{Fuel consumption (scf/hr) x Measured fuel heating value (LHV btu/scf)}}{\text{Manufacturer's rated BSFC (btu/bhp-hr) at 100\% load or best efficiency}}$$

$$\text{Load (Hp)} = \frac{\text{Fuel consumption (gal/hr) x Measured fuel heating value (LHV btu/gal)}}{\text{Manufacturer's rated BSFC (btu/bhp-hr) at 100\% load or best efficiency}}$$

Where: LVH = lower heating value, btu/scf, or btu/gal, as appropriate; and
BSFC = brake specific fuel consumption

If the manufacturer's rated BSFC is not available, an operator may use an alternative load calculation methodology based on available data.

(a) emissions testing events shall be conducted within 10 percent of 100 percent peak (or the highest achievable) load. ~~at ninety percent or greater of the unit's capacity. If the ninety percent capacity cannot be achieved, the monitoring and testing shall be conducted at the maximum achievable capacity or load under prevailing operating conditions~~. The load and the parameters used to calculate it shall be recorded to document operating conditions at the time of testing and shall be included with the test report.

(b) emissions testing utilizing a portable analyzer shall be conducted in accordance with the requirements of the current version of ASTM D6522. If a portable analyzer has met a previously approved department criterion, the analyzer may be operated in accordance with that criterion until it is replaced.

(c) the default time period for a test run shall be at least 20 minutes.

(d) an emissions test shall consist of three separate runs, with the arithmetic mean of the results from the three runs used to determine compliance with the applicable emission standard.

(e) during emissions tests, pollutant and diluent concentration shall be monitored and recorded. Fuel flow rate shall be monitored and recorded if stack gas flow rate is determined utilizing U.S. EPA reference method 19. This information shall be included with the periodic test report.

(f) stack gas flow rate shall be calculated in accordance with U.S. EPA reference method 19 utilizing fuel flow rate (scf) determined by a dedicated fuel flow meter and fuel heating value (Btu/scf). The owner or operator shall provide a contemporaneous fuel gas analysis (preferably on the day of the test, but no earlier than three months before the test date) and a recent fuel flow meter calibration certificate (within the most recent quarter) with the final test report. Alternatively, stack gas flow rate may be determined by using U.S. EPA reference methods 1 through 4 or through the use of manufacturer provided fuel consumption rates.

(g) upon request by the department, an owner or operator shall submit a notification and protocol for an initial or annual emissions test.

(h) emissions testing shall be conducted at least once per calendar year. Emission testing required by Subparts GG, IIII, JJJJ, or KKKK of 40 CFR 60, or Subpart ZZZZ of 40 CFR 63, may be used to satisfy the emissions testing requirements if it meets the requirements of 20.2.50.113 NMAC and is completed at least once per calendar year.

Comment on 20.2.50.113(C)(3): Redline required to replace with term manufacturers specification as defined in 20.2.50.112 as this specific manufacturer's data is frequently not available for most units older than 2000. Thus, an alternate calculation must be allowed. BSFC is regularly determined through current engineering practices and does not rely on manufacturer's rate. Changes to the timing of performance tests also made for consistency with 40 C.F.R. 60.8(a).

Comment on 20.2.50.113(C)(3)(a): Redline matches language in NSPS Subpart JJJJ.

(4) The owner or operator of equipment operated less than 500 hours per year shall monitor the hours of operation using a non-resettable hour meter and shall test the unit at least once per 8760 hours of operation in accordance with the emissions testing requirements in Paragraph (3) of Subsection C of 20.2.50.113 NMAC.

(5) An owner or operator of an emergency use engine as defined by 40 C.F.R. §§ 60.4211, 60.4243, or 63.6675~~operated for less than 100 hours per year~~ shall monitor the hours of operation by a non-resettable hour meter.

(6) An owner or operator limiting the annual operating hours of an engine to meet the requirements of Paragraph (2) or Paragraph (7) of Subsection B of 20.2.50.113 NMAC shall monitor the hours of operation by a non-resettable hour meter.

~~**(7)** Prior to monitoring, testing, inspection, or maintenance of an engine or turbine, the owner or operator shall scan the EMT, and the monitoring data entry shall be made in accordance with the requirements of 20.2.50.112 NMAC.~~

D. Recordkeeping requirements:

(1) The owner or operator of a spark ignition engine, compression ignition engine, or stationary combustion turbine shall maintain a record in accordance with 20.2.50.112 NMAC for the engine or turbine. The record shall include:

(a) the make, model, serial number, ~~and EMT~~ for the engine or turbine;

(b) a copy of the maintenance and repair schedule for the engine, turbine, or control device as recommended by the manufacturer or as developed consistent with good operational and maintenance practices~~manufacturer recommended maintenance and repair schedule~~;

(c) all inspection, maintenance, or repair activity on the engine, turbine, and control device, including:

(i) the date and time of an inspection, maintenance or repair;

(ii) the date a subsequent analysis was performed (if applicable);

(iii) the name of the ~~personnel~~ person(s)conducting the inspection, maintenance or repair;

(iv) a description of the physical condition of the equipment as found during the inspection;

(~~v~~iv) a description of maintenance or repair activity conducted; and

(~~vi~~v) the results of the inspection and any required corrective actions.

(2) The owner or operator of a spark ignition engine, compression ignition engine, or stationary combustion turbine shall maintain records of initial and annual emissions testing for the engine or turbine for a period of 5 years. The records shall include:

(a) the make, model, and serial number~~, and EMT~~ for the tested engine or turbine;

(b) the date and time of sampling or measurements;

(c) the date analyses were performed;

(d) the name of the ~~personnel~~ person(s) and the qualified entity that performed the analyses;

(e) the analytical or test methods used;

(f) the results of analyses or tests;

(g) for equipment operated less than 500 hours per year, the total annual hours of operation as recorded by the non-resettable hour meter; and

(h) operating conditions at the time of sampling or measurement.

(3) The owner or operator of an emergency use engine as defined by 40 C.F.R. §§ 60.4211, 60.4243, or 63.6675 ~~operated less than 100 hours per year~~shall record the total annual hours of operation as recorded by the non-resettable hour meter.

(4) The owner or operator limiting the annual operating hours of an engine to meet the requirements of Paragraph (2) or Paragraph (7) of Subsection B of 20.2.50.113 NMAC shall record the hours of operation by a non-resettable hour meter. The owner or operator shall calculate and record the annual NOx and VOC emission calculation, based on the engine's actual hours of operation, to demonstrate that an equivalent allowable ton per year emission as set forth in Table 1 of Paragraph (2) of Subsection B of 20.2.50.113 NMAC or the ninety-five percent emission reduction requirement is met.

(5) An owner or operator claiming an exemption under Paragraph 2(e) or Paragraph (7)(a)(v) of Subsection B of 20.2.50.113 must maintain records for each engine or turbine, as applicable, demonstrating that the exemption applies.

(6) An owner operator that received an extension of the effective dates for an emissions standards set forth in Paragraph (2) or Paragraph (7) of Subsection B of 20.2.50.113 NMAC must maintain records of the extension for good cause shown.

E. **Reporting requirements:** The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.
[20.2.50.113 NM–C - N, XX/XX/2021]

20.2.50.114 COMPRESSOR SEALS:

Comment on 20.2.50.114: NMOGA recommends that the Compressor Seals section be completely removed from the proposed rule. According to the ERG memo, total emissions from compressor seals (VOCs) is 0.006% of total VOC emissions from compression, which is estimated at 13 tons/year. The proposed rules would at best only reduce the tonnage by 6 tons/year, or 0.005% of the calculated VOCs post rule. Because it is not common practice to collect the gas from compressor seals, there is no industry standard for how to mechanically solve the issue. It is most certainly not the "low hanging fruit" for NMED. Short of striking the entire section, NMED should remove the "collect compressor vents under negative pressure" statement allowing operators to determine most effective method of collecting that vent, especially because a solution is not common practice.
Reference Valor Memo - Engines and Turbines.

A. **Applicability:**

(1) Centrifugal compressors using wet seals and located at tank batteries, gathering and boosting sites, natural gas processing plants, or transmission compressor stations are subject to the requirements of 20.2.50.114 NMAC. Centrifugal compressors located at ~~wellhead sites~~well production facilities and their associated tank batteries are not subject to the requirements of 20.2.50.114 NMAC.

(2) Reciprocating compressors located at tank batteries, gathering and boosting sites, natural gas processing plants, or transmission compressor stations are subject to the requirements of 20.2.50.114 NMAC. Reciprocating compressors located at ~~wellhead sites~~well production facilities and their associated tank batteries are not subject to the requirements of 20.2.50.114 NMAC.

B. **Emission standards:**

(1) The owner or operator of an existing centrifugal compressor shall control VOC emissions from a centrifugal compressor wet seal fluid degassing system by at least ninety-five percent within two years of the effective date of this Part. Emissions shall be captured and routed via a closed vent system to a control device, recovery system, fuel cell, or a process stream.

(2) The owner or operator of an existing reciprocating compressor shall, either:

(a) replace the reciprocating compressor rod packing after every 26,000 hours of compressor operation or every 36 months, whichever is reached later. The owner or operator shall begin counting the hours of compressor operation toward the first replacement of the rod packing upon the effective date of this Part; or

(b) beginning no later than two years from the effective date of this Part, collect emissions from the rod packing ~~under negative pressure~~ and route them via a closed vent system to a control device, recovery system, fuel cell, or a process stream.

(3) The owner or operator of a new centrifugal compressor with wet seals shall control VOC emissions from the centrifugal compressor wet seal fluid degassing system by at least ninety-eight percent upon startup. Emissions shall be captured and routed via a closed vent system to a control device, recovery system, fuel cell, or process stream.

(4) The owner or operator of a new reciprocating compressor shall, upon startup, either:

(a) replace the reciprocating compressor rod packing after every 26,000 hours of compressor operation, or every 36 months, whichever is reached later; or

(b) collect emissions from the rod packing ~~under negative pressure~~ and route them via a closed vent system to a control device, a recovery system, fuel cell or a process stream.

~~**(5)** The owner or operator of a centrifugal or reciprocating compressor shall install an EMT on the compressor in accordance with 20.2.50.112 NMAC.~~

(5~~6~~) The owner or operator complying with the emission standards in Subsection B of 20.2.50.114 NMAC through use of a control device shall comply with the control device requirements in 20.2.50.115 NMAC.

Comment on 20.2.50.114(B)(2)(b): Redline required as "under negative pressure" is overly prescriptive; raises mechanical integrity, oxygen entrainment, and safety concerns; and does not allow flexibility for new technology or new facility concepts. NMED should keep requirement to have closed vent system and control but leave it up to the operator to determine the best method to execute.

C. **Monitoring, testing, and inspection requirements:**

(1) The owner or operator of a centrifugal compressor complying with Paragraph (1) or (3) of Subsection B of 20.2.50.114 NMAC shall maintain a closed vent system encompassing the wet seal fluid degassing system that complies with the ~~monitoring~~monitoring, testing, or inspection requirements in 20.2.50.115 NMAC.

(2) The owner or operator of a reciprocating compressor complying with Subparagraph (a) of Paragraph (2) or Subparagraph (a) of Paragraph (4) of Subsection B of 20.2.50.114 NMAC shall continuously monitor the hours of operation with a non-resettable hour meter and track the number of hours since initial startup or since the previous reciprocating compressor rod packing replacement.

(3) The owner or operator of a reciprocating compressor complying with Subparagraph (b) of Paragraph (2) or Subparagraph (b) of Paragraph (4) of Subsection B of 20.2.50.114 NMAC shall monitor the rod packing emissions collection system semiannually to ensure that it operates as designed ~~under negative pressure~~ and routes emissions through a closed vent system to a control device, recovery system, fuel cell, or process stream.

(4) The owner or operator of a centrifugal or reciprocating compressor complying with the requirements in Subsection B of 20.2.50.114 NMAC through use of a closed vent system or control device shall comply with the ~~monitoring~~monitoring, testing, or inspection requirements in 20.2.50.115 NMAC.

(5) The owner or operator of a centrifugal or reciprocating compressor shall comply with the ~~monitoring~~monitoring, testing, or inspection requirements in 20.2.50.112 NMAC.

Comment on 20.2.50.114(C)(3): Redline to align with above comment [20.2.50.114(B)(2)(b)].

D. Recordkeeping requirements:

(1) The owner or operator of a centrifugal compressor using a wet seal fluid degassing system shall maintain a record of the following:

(a) the location of the centrifugal compressor;

(b) the date of construction or reconstruction ~~or modification~~ of the centrifugal compressor;

(c) the ~~monitoring~~monitoring, testing, or inspection required in Subsection C of 20.2.50.114 NMAC, including the time and date of the ~~monitoring~~monitoring, testing, or inspection, the ~~personnel~~ person(s) conducting the ~~monitoring~~monitoring, testing, or inspection, a description of any problem observed during the ~~monitoring~~monitoring, testing, or inspection, and a description of any corrective action taken; and

(d) the type, make, model, and identification number or equivalent identifier of a control device used to comply with the control requirements in Subsection B of 20.2.50.114 NMAC.

(2) The owner or operator of a reciprocating compressor shall maintain a record of the following:

(a) the location of the reciprocating compressor;

(b) the date of construction~~,~~ or reconstruction~~, or modification~~ of the reciprocating compressor; and

(c) the ~~monitoring~~monitoring, testing, or inspection required in Subsection C of 20.2.50.114 NMAC, including:

(i) the number of hours of operation since the effective date, initial startup after the effective date, or the last rod packing replacement, as applicable;

(ii) data showing effectiveness of ~~the records of pressure in~~ the rod packing emissions collection system, as applicable, and

(iii) the time and date of the monitoring, testing or inspection, the ~~personnel~~ person(s) conducting the monitoring, testing or inspection, ~~a notation of which checks required in Subsection C of 20.2.50.114 NMAC were completed,~~ a description of any problems observed during the monitoring, testing or inspection, and a description and date of corrective actions taken.

(3) The owner or operator of a centrifugal or reciprocating compressor complying with the requirements in Subsection B of 20.2.50.114 NMAC through use of a control device or closed vent system shall comply with the recordkeeping requirements in 20.2.50.115 NMAC.

(4) The owner or operator of a centrifugal or reciprocating compressor shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

Comment on 20.2.50.114(D)(1)(b): Redline required because definitions for construction and reconstruction include modification.

Comment on 20.2.50.114(D)(2)(c)(ii): Redline required to align with striking negative pressure. Alternative methods should be allowed to show effectiveness (e.g., bubble soak test, helium mass spec test, etc).

Comment on 20.2.50.114(D)(2)(c)(iii). Redline recommended because the reference to notations for checks required under Subsection C is vague. The rule should specify the recordkeeping requirements with specificity to give the regulated community *fair notice.*

E. Reporting requirements: The owner or operator of a centrifugal or reciprocating compressor shall comply with the reporting requirements in 20.2.50.112 NMAC.
[20.2.50.114 NM–C - N, XX/XX/2021]

20.2.50.115 CONTROL DEVICES AND CLOSED VENT SYSTEMS:

A. Applicability: These requirements apply to control devices and closed vent systems as defined in 20.2.50.7 NMAC and used to comply with the emission standards and emission reduction requirements in this Part.

Comment on 20.2.50.115: Redline for clarification as this section also contains requirements for closed vent systems.

B. General requirements:

(1) Control devices used to demonstrate compliance with this Part shall be installed, operated, and maintained consistent with manufacturer specifications; or installed, operated, and maintained in accordance with ~~, and~~ good ~~engineering~~ operating and maintenance practices~~.~~

(2) Control devices shall be adequately designed and sized to achieve the control efficiency rates required by this Part and to handle the reasonably expected range of inlet VOC or NOx concentrations or volumes. ~~fluctuations in emissions of VOC or NOx.~~

~~(3) The owner or operator of a control device used to comply with the emission standards in this Part shall install an EMT on the control device in accordance with 20.2.50.112 NMAC.~~

(~~4~~3) The owner or operator shall inspect visually, or consistent with federally approved inspection methods, control devices ~~used to comply with this Part~~ at least monthly to identify defects, leaks, and releases. ~~ensure proper maintenance and operation. Prior to an inspection or monitoring event, the owner or operator shall scan the EMT and the required monitoring data shall be electronically captured in accordance with this Part.~~

(~~5~~4) The owner or operator shall ensure that a control device used to comply with emission standards in this Part operates as a closed vent system that captures and routes VOC emissions to the control device~~, and that unburnt gas is not directly vented to the atmosphere~~.

(~~6~~5) The owner or operator of a permanent closed vent system for a centrifugal compressor wet seal fluid degassing system, reciprocating compressor, pneumatic ~~controller or~~ pump, or storage vessel using a control device or routing emissions to a process shall:

(a) ensure the control device or process is of sufficient design and capacity to accommodate the reasonably expected range of ~~all~~ emissions from the affected sources;

(b) conduct an assessment to confirm that the closed vent system is of sufficient design and capacity to ensure that ~~all~~ emissions from the affected equipment are routed to the control device or process; and

(c) have the ~~closed vent system~~ assessment certified by a qualified professional engineer or an in-house ~~engineer~~ employee with expertise regarding the design and operation of ~~the~~ closed vent systems in accordance with Paragraphs (c)(i) and (ii) of this Section.

(i) The assessment of the closed vent system shall be prepared under the direction or supervision of a qualified professional engineer or ~~an~~ the in-house ~~engineer~~ employee who signs the certification in Paragraph (c)(ii) of this Section.

(ii) the owner or operator shall provide the following certification, signed and dated by a qualified professional engineer or an in-house ~~engineer~~employee: "I certify that the closed vent system ~~design and capacity~~ assessment was prepared under my direction or supervision. I further certify that the closed vent system ~~design and capacity~~ assessment was conducted, and this report was prepared pursuant to the requirements of this Part. Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete."

(~~7~~6) The owner or operator shall keep manufacturer specifications for all control devices installed after the effective date on file. The information shall include the manufacturer name, make, and model and relevant capacity and efficiency data.~~:~~

~~(a) manufacturer name, make, and model;~~
~~(b) maximum heating value for an open flare, ECD, or TO;~~
~~(c) maximum rated capacity for an open flare, ECD/TO, or VRU;~~
~~(d) gas flow range for an open flare, ECD, or TO; and~~
~~(e) designed destruction or vapor recovery efficiency,.~~

Comment on 20.2.50.115(B)(1): Redline required because, for many pieces of equipment, particularly equipment purchased *before the applicability of this rule, manufacturer specifications may not be readily available. In addition, experience in the field sometimes dictates adopting procedures that differ in some respects from manufacturer recommendations.*

Comment on 20.2.50.115(B)(2): Redline required as control devices are designed for anticipated range of flowrates, pressures, and compositions. However, in many cases, compositions, flows, and pressures change during normal operations in ways that are not anticipated. Engineers can only design to predictable conditions.

Comment on 20.2.50.115(B)(3): Redline required to clarify that inspections conducted pursuant to federal standards, such as 40 C.F.R. Part 60 Subparts OOOO and OOOOa, are adequate to meet the monthly inspection requirement. See, e.g., 40 C.F.R. 60.5416(c) (requiring monthly inspection of certain closed vent systems). These federal inspections are designed and proven to achieve the same objective as NMED's rule—to ensure proper performance of control device systems.

Comment on 20.2.50.115(B)(4): Redline required as this statement is counter intuitive. A control device with a certain DRE% will only combust or destruct gas up to that DRE%. Any unburnt gas (i.e., 100-DRE) percent must be assumed to be directly vented to atmosphere. As written, the statement of "unburnt gas is not directly vented to the atmosphere" implies a 100% DRE device.

Comment on 20.2.50.115(B)(5): Redline required to align the standard with 40 C.F.R. Part 60, Subpart OOOOa. NMED has largely incorporated the language of 40 C.F.R. 60.5411a(d). However, unlike NMED's proposal, EPA did not include pneumatic controllers because, as it has expressed elsewhere, use of closed vent systems with pneumatic controllers is not a "viable control option." 81 Fed. Reg. 35824, 35879 (Jun. 3, 2016). Pneumatic controller actuations require a sudden change in pressure, and any back pressure on the device could impact its ability to function, making application of closed vent systems impractical.

Comment on 20.2.50.115(B)(5)(a), (b): It is unreasonable to require that "all" emissions be controlled at all times as systems must be designed for expected conditions and not every possible condition can be anticipated.

Comment on 20.2.50.115(B)(5)(c): Redline required to indicate that an "assessment" can be an open loop or closed loop vapor control system approach. The closed loop vapor control system approach, for example, utilizes a series of feedback control loops from storage vessels to control upstream equipment based on storage vessel pressure. This approach has been deemed "closed loop control" method, and has been approved as acceptable substitute for closed vent system analysis (which is a theoretical model) in recent consent decrees (ref High Point Resources, KPK Kauffman) and EPA's new owner self audit agreement. "Assessment" can either mean the results for a theoretical model (i.e., open loop method) or another method such as the results of a functioning automation system (e.g., closed loop vapor control system).

Comment on 20.2.50.115(B)(5)(c)(i)-(ii). Redline required because, in many instances, in-house experts are better trained and capable of assessing such systems than someone that is a licensed professional engineer. There are likely very few licensed professional engineers that are actually versed in the details of such systems. Requiring operators to find and use such individuals would create undue hardship with no emissions benefit.

Comment on 20.2.50.115(B)(6)(a)-(e). For existing sources, manufacturer's specifications may have never existed, may have been lost, or may no longer be maintained by the manufacturer. Moreover, even where these specifications do exist, they may not be appropriate for some equipment due to enhancements in technology or information gleaned based on company or industry experience using the equipment in our specific service. To the extent that these specifications are needed to demonstrate compliance with technical standards, the rule should permit alternative means of demonstrating compliance.

C. Requirements for open flares:

(1) Emission standards:

(a) The flare shall be properly sized and designed to ensure proper combustion efficiency to combust the gas sent to the flare~~ and combustion shall be maintained for the duration of time that gas is sent to the flare~~. The owner or operator shall not send gas to the flare outside the bounds of the design capacity.~~in excess of the manufacturer maximum rated capacity.~~

(b) the owner or operator shall equip each new ~~and existing~~ flare (except those flares required to meet the requirements of Paragraph (~~C~~D) of this Subsection) with a continuous pilot flame or ~~an~~ operational auto-igniter~~, or require manual ignition~~, and shall comply with the following:

(i) a flare with a continuous pilot flame or an auto-igniter shall be equipped with a system to ensure the flare is operated with a flame present at all times when gas is being sent to the flare.

~~**(ii)** the owner or operator of a flare with manual ignition shall inspect and ensure a flame is present upon initiating a flaring event.~~

(ii~~i~~) a new flare controlling a continuous gas stream shall be equipped with a continuous pilot flame or auto-igniter upon startup.

~~**(iv)**~~ **(c)** the owner or operator shall equip each existing flare (except those flares required to meet the requirements of paragraph (D) of this Subsection) with an automatic ignitor, continuous pilot, or technology that alerts the operator that the flare may have malfunctioned no later than two years after the effective date. ~~an existing flare controlling a continuous gas stream constructed before the effective date of this Part shall be equipped with a continuous pilot no later than one year after the effective date of this Part.~~

(~~c~~d) an existing flare located at a site with an annual average daily production of equal to or less than ~~10 barrels of oil per day or an average daily production of~~ 60,000 standard cubic feet of natural gas shall be equipped with an auto-ignitor or ~~,~~ continuous pilot~~, or technology (e.g. alarm) that alerts the owner or operator of a flare malfunction~~, if replaced ~~or reconstructed~~ after the effective date of this Part.

(~~d~~e) the owner or operator shall operate a flare with no visible emissions, except for periods not to exceed a total of 30 seconds during any 15 consecutive minutes. The flare shall be designed so that an observer can, by means of visual observation from the outside of the flare or by other means such as a continuous monitoring device, determine whether it is operating properly. The observation may be terminated if visible emissions are identified and recorded or action is taken to address visible emissions.

(~~e~~f) the owner or operator shall initially attempt to repair the flare within three business days of any thermocouple or other flame detection device alarm activation.

Comment on 20.2.50.115(C)(1)(a): The owner or operator can guarantee that flare is designed to ensure proper combustion efficiency. The proposed language aligns with the recently adopted NMOCD rule, 19.15.27.8.E(3) NMAC. In addition, the provisions of 20.2.50.115.C.(1)(b)-(f) provide assurance that the flare will combust gases sent to it.

Comment on 20.2.50.115(C)(1)(b)(i)-(ii): Redline required to align with NMOCD venting and flaring rule. NMOCD does not allow for manual ignition.

Comment on 20.2.50.115(C)(1)(b)(i): A flare equipped with an auto igniter is inherently equipped with a system to ensure the flare is operated with a flame present at all times because it auto ignites in the presence of gas.

Comment on 20.2.50.115(C)(1)(d): Redline required to align with OCD Waste Rule. As that rule and this one are focused on gas waste and gas related emissions, respectively, it is appropriate to apply flexibilities like this one based upon gas rate through the site.

Comment on 20.2.50.115(C)(1)(e): Redline required because under the proposed standard, if 30 seconds of visible emissions are observed during a 15-minute period, further evaluation is not necessary to evaluate compliance with the standard. As written, the rule appears to require the observation to continue, even if visible emissions violating the standard are observed. NMOGA would prefer the flexibility to end the observation once a violation is observed so that it can begin to address the underlying cause.

Comment on 20.2.50.115(C)(1)(f): Redline required because it may take longer than three business days to repair.
For flares where thermal monitoring is appropriate, NMOGA agrees monitoring alarms is appropriate. The regulation should include a qualifier to clarify the narrow scope of this requirement (e.g., "thermocouple or other flame detection device alarm activation"). NMOGA also requests the provision not require recording false alarms due to wind or other weather- related events. For example, wind may create distance between the thermocouple and the flame and trip the alarm, even though the flame continues to be ignited.

(2) Monitoring, testing, and inspection requirements:

(a) the owner or operator of a new permanent flare with a continuous pilot or auto igniter shall continuously monitor the presence of a pilot flame, or presence of flame during flaring if using an auto igniter, using a thermocouple equipped with a continuous recorder and alarm to detect the presence of a flame. An alternative equivalent technology alerting the owner or operator of failure of ignition of the gas stream may be used in lieu of a continuous recorder and alarm, if approved by the department;

~~**(b)** the owner or operator of a manually ignited flare shall monitor the presence of a flame using continuous visual observation during a flaring event;~~

(b~~e~~) the owner or operator shall~~, at least quarterly, and~~ upon observing visible emissions for a period of time 30 seconds, perform a U.S. EPA method 22 observation while the flare pilot or auto igniter flame is present to certify compliance with visible emission requirements. The observation period shall be a minimum of 15 consecutive minutes. The observation may be terminated if visible emissions are identified and recorded or action is taken to address visible emissions.~~to address the visible emissions.~~

~~**(d)** prior to an inspection or monitoring event, the EMT on the flare shall be scanned and the required monitoring data shall be electronically captured during the event in accordance with the monitoring requirements of 20.2.50.112 NMAC; and~~

(c~~e~~) the owner or operator shall monitor the technology that alerts the owner or operator of a flare malfunction and any instances of technology or alarm activation.

Comment on 20.2.50.115(C)(2)(a): NMOGA requests this provision be revised consistent with the discussion above to not require retrofitting for existing facilities.

Comment on 20.2.50.115(C)(2)(b): Redline required to align with NMOCD venting and flaring rule.

Comment on 20.2.50.115(C)(2)(b): Redline required because under the proposed standard, if 30 seconds of visible emissions are observed during a 15-minute period, further evaluation is not necessary to evaluate compliance with the standard. As written, the rule appears to require the observation to continue, even if visible emissions violating the standard are observed. NMOGA would prefer the flexibility to end the observation once a violation is observed so that it can begin to address the underlying cause.

Comment on 20.2.50.115(C)(2)(d): Redline required to remove EMT as described in General Provisions.

(3) Recordkeeping requirements: The owner or operator of an open flare shall keep a record of the following, as applicable:

(a) any instance of thermocouple or other flame detection device alarm activation, including the date and cause of alarm activation, action taken to bring the flare into a normal operating condition, the name of the ~~personnel~~ person(s) conducting the inspection, and any maintenance activity performed;

(b) the results of any~~the~~ U.S. EPA method 22 observations;

~~**(c)** the monitoring of the presence of a flame on a manual flare during a flaring event as required under Subparagraph (b) of Paragraph (2) of Subsection C of 20.2.50.115 NMAC;~~

(d) the results of the most recent gas analysis (sampled or modeled) for the gas being flared, including VOC content and heating value, if any; and

e) any instance of technology or alarm activation of a malfunctioning flare, including the date and cause of the activation, the action taken to bring the flare into normal operating condition, ~~date of repair, name of the personnel conducting the inspection, and any maintenance activities performed.,~~

Comment on 20.2.50.115(C)(3)(c): Redline required to align with NMOCD venting and flaring rule.

Comment on 20.2.50.115(C)(3)(d): Redline required as gas samples may be representative samples from adjacent or representative facilities. Redline clarifies to retain sample reports if available. Redline further makes clear that the results of the gas analysis for the gas flared may use modeling (based on a liquids analysis) of the gas going to the flare.

(4) Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

D. Requirements for enclosed combustion devices (ECD) and thermal oxidizers (TO):

(1) Emission standards:

(a) the ECD/TO shall be properly sized and designed to ensure proper combustion efficiency to combust the gas sent to the ECD/TO. The owner or operator shall not send gas to the ECD/TO in excess of the manufacturer maximum rated capacity.

(b) the owner or operator shall equip each new~~an~~ ECD/TO with a continuous pilot flame or an auto-igniter. New ECD/TO with a continuous pilot flame shall be equipped with a system to ensure the ECD/TO is operated with a flame present at all times when gas is being sent to ECD/TO. Existing ECD/TO shall be equipped with a continuous pilot flame or an auto-igniter no later than two years after the effective date. ~~ne year after the effective date~~. ~~New ECD/TO shall be equipped with a continuous pilot flame or an auto-igniter upon startup.~~

~~**(c)** ECD/TO with a continuous pilot flame or an auto-igniter shall be equipped with a system to ensure that the ECD/TO is operated with a flame present at all times when gas is sent to the ECD/TO. Combustion shall be~~

~~maintained for the duration of time that gas is sent to the ECD/TO.~~

(~~d~~c) the owner or operator shall operate an ECD/TO with no visible emissions, except for periods not to exceed a total of 30 seconds during any 15 consecutive minutes. The ECD/TO shall be designed so that an observer can, by means of visual observation from the outside of the ECD/TO or by other means such as a continuous monitoring device, determine whether it is operating properly. The observation may be terminated if visible emissions are identified and recorded or action is taken to address visible emissions.

(2) Monitoring, testing, and inspection requirements:

(a) the owner or operator of a new permanent ECD/TO with a continuous pilot shall continuously ~~or an auto igniter~~monitor the presence of a pilot flame ~~or of a flame during combustion if using an auto-igniter,~~using a thermocouple equipped with a continuous recorder and alarm to detect the presence of a flame. An alternative equivalent technology alerting the owner or operator of failure of ignition of the gas stream may be used in lieu of a continuous recorder and alarm, if approved by the department.

(b) the owner or operator shall, ~~at least quarterly, and~~ upon observing visible emissions for a period of time exceeding 30 seconds, perform a U.S. EPA method 22 observation while the ECD/TO pilot flame or auto igniter flame is present to certify compliance with the visible emission requirements. The period of observation shall be a minimum of 15 consecutive minutes. The observation may be terminated to if visible emissions are identified and recorded or action is taken address visible emissions.

~~(c) prior to an inspection or monitoring event, the EMT on the unit shall be scanned and the required monitoring data shall be electronically captured during the monitoring event in accordance with the monitoring requirements of 20.2.50.112 NMAC.~~

(3) Recordkeeping requirements: The owner or operator of an ECD/TO shall keep records of the following, as applicable:

(a) any instance of a thermocouple or other flame detection device ~~n~~ alarm activation, including the date and cause of the activation, any action taken to bring the ECD/TO into normal operating condition, the name of the ~~personnel~~ person(s) conducting the inspection, and any maintenance activities performed;

(b) the result of ~~the~~ any U.S. EPA method 22 observation; and

(c) the results of the most recent gas analysis (sampled or modeled) for the gas being combusted, including VOC content and heating value~~.~~, if any,

(4) Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

Comment on 20.2.50.115(D)(1)(a): Redline to align with comment in flare section above (20.2.50.115(C)(1)(a):)

Comment on 20.2.50.115(D)(1)(c): Redline required to align with NMOCD requirements for flares (20.2.50.115(C)(1)(a)

Comment on 20.2.50.115(D)(2)(a): Redline required as auto-igniter ECD/TOs do not have a continuous flame and should not be included in this provision. NMOGA also requests this provision be revised consistent with the discussion above to not require retrofitting for existing facilities.

Comment on 20.2.50.115(D)(2)(c): Redline required to remove EMT as described in General Provisions.

Comment on 20.2.50.115(D)(3)(c): Redline required as gas samples may be representative samples from adjacent or representative facilities. Redline clarifies to retain sample reports if available. Redline further makes clear that the results of the gas analysis for the gas flared may use modeling (based on a liquids analysis) of the gas going to the flare

E. Requirements for vapor recovery capture units (VRCU):

(1) Emission standards:

(a) the owner or operator shall operate the VRCU as a closed vent system that captures and routes ~~all~~ VOC emissions directly back to the process or to a sales pipeline and does not vent to the atmosphere.

(b) the owner or operator shall control VOC emissions during startup, shutdown, maintenance, or other ~~VRU~~VRCU downtime with a backup control device (e.g. flare, ECD, TO) or redundant VRCU~~VRU.~~ during the period of VRCU downtime unless otherwised approved in state permit. Alternatively, the owner or operator may shut down and isolate the source being controlled by the VRCU.

(2) Monitoring, testing, and inspection ~~Requirements~~requirements:

(a) the owner or operator shall comply with the standards for equipment leaks in 20.2.50.116 NMAC, or, alternatively, shall implement a program that meets the requirements of Subpart OOOOa of 40 CFR 60.

~~(b) prior to a VRU inspection or monitoring event, the EMT on the unit shall be scanned and the required monitoring data shall be electronically captured during the monitoring event in accordance with the monitoring~~

~~requirements of 20.2.50.112 NMAC.~~

(3) Recordkeeping requirements: ~~For a VRU inspection or monitoring event, the ownoperator shall record the result of the event in accordance with 20.2.50.112 NMAC, including the name of the personnel conducting the inspection, and any maintenance or repair activities re~~The owner or operator shall record the type of redundant control device used during VRCU downtime or alternatively keep records of the equipment shut down and isolated as well as the time period over which it was shut down or records regarding compliance with the state permit.

(4) Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

Comment on 20.2.50.115(E)(1)(b): Redline required as an operator should have the option of not operating a unit (e.g. Tank) with a VRCU rather than having redundant control or backup control. For example, an operator could shut-in a well(s) to service a VRCU on the tanks receiving hydrocarbon fluid from that well (s) rather than have redundant control systems.

Comment on 20.2.50.115(E)(3): Redline required as record keeping is addressed under LDAR section. Redline required as an operator should have the option of not operating a unit (e.g. Tank) with a VRCU rather than having redundant control or backup control. For example, an operator could shut-in a well(s) to service a VRCU on the tanks receiving hydrocarbon fluid from that well (s) rather than have redundant control systems.

F. Recordkeeping requirements: The owner or operator of a control device or closed vent system shall maintain a record of the following:

(1) the certification of the closed vent system where applicable and ~~as~~ required by this Part; and

(2) the information required in Paragraph (7) of Subsection B of 20.2.50.115 NMAC.

G. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.115 NM–C - N, XX/XX/2021]

20.2.50.116 EQUIPMENT LEAKS AND FUGITIVE EMISSIONS:

A. Applicability: ~~Wellhead sites~~Well production facilities, tank batteries, gathering and boosting sites, gas processing plants, transmission compressor stations, and associated piping and components are subject to the requirements of 20.2.50.116 NMAC. Equipment leak and fugitive emissions -monitoring required by New Source Performance Standards, including but not limited to Subpart OOOO and Subpart OOOOa, 40 C.F.R. Part 60, as may be revised, may be used to satisfy the requirements of this 20.2.50.116 NMAC. A component is subject to the requirements if it is a gas vapor or light liquid component that contacts process fluid that is at least 10% VOC by weight. Components in water and/or air service are exempt from the requirements of 20.2.50.116 NMAC. Well production facilities and gathering and boosting sites producing or handling exclusively coal bed methane are not subject to the requirements of 20.2.50.116. The requirements of this Part may be considered in the facility's PTE and in determining the monitoring frequency requirements of this Section.

Comment on 20.2.50.116.A. Redlined required to exempt facilities already performing robust equipment leak monitoring under New Source Performance Standards. The ten-percent VOC threshold is added to exempt from the rule components that do not contain liquids capable of emitting meaningful amounts of VOC. Similarly, NMOGA has added the exemption for water and/or air service components because these do not leak VOCs. Coal bed methane wells or gathering and boosting sites handling coal bed methane should also be excluded because they do not have the potential to emit VOC's due to equipment leaks since the gas they produce or handle has no VOC to emit and there are no hydrocarbon liquids produced or handled.

NMOGA has included language consistent with NMED Exhibit 41 regarding the consideration of proposed Part 50 standards for determining PTE and LDAR thresholds.

B. Emission standards: The owner or operator of oil and gas production and processing equipment located at wellhead sites, tank batteries, gathering and boosting sites, gas processing plants, or transmission compressor stations shall demonstrate compliance with this Part by performing the monitoring, recordkeeping, and reporting requirements specified in 20.2.50.116 NMAC.

C. ~~**Default**~~ **Monitoring, inspection or testing requirements:** Owners and operators shall comply with the following monitoring requirements: ~~and the monitoring requirements in 20.2.50.112 NMAC:~~

(1) The owner or operator of a well production facility or tank battery ~~facility~~ with an annual ~~average daily production of greater than 10 barrels of oil per day or an~~ average daily production or average daily throughput of greater than 60,000 standard cubic feet per day of natural gas shall, at least weekly, conduct audio, visual, and olfactory (AVO) inspections of thief hatches, closed vent systems, pumps, compressors, pressure relief devices, open-ended valves or lines, valves, flanges, connectors, piping, and associated equipment to identify defects and leaking components as follows:

(a) conduct an external visual inspection for defects which may include~~:~~ cracks, holes, or gaps in piping or covers; loose connections; liquid leaks; broken or missing caps; broken, cracked or otherwise damaged seals or gaskets; broken or missing hatches; or broken or open access covers or other closure or bypass devices;

(b) conduct an audio inspection for pressure leaks and liquid leaks;

(c) conduct an olfactory inspection for unusual or strong odors;

(d) any positive detection during the AVO inspection shall be ~~be considered a leak; and~~

~~**(e)** a leak discovered by an AVO inspection shall be tagged with a visible tag~~ repaired in accordance with Subsection E if not repaired at the time of discovery. ~~and reported to management or their designee within three calendar days.~~

(2) The owner or operator of a well production facility or tank battery ~~facility~~ with an annual ~~average daily production of equal to or less than 10 barrels of oil per day or an~~ average daily production or average daily throughput of equal to or less than 60,000 standard cubic feet per day of natural gas shall, at least monthly, conduct an audio, visual, and olfactory (AVO) inspection of thief hatches, closed vent systems, pumps, compressors, pressure relief devices, open-ended valves or lines, valves, flanges, connectors, piping, and associated equipment to identify a defect and leaking component as specified in Subparagraphs (a) through (e) of Paragraph (1) of Subsection (C) of 20.2.50.116 NMAC.

(3) The owner or operator of the following facilities shall conduct an inspection using U.S.EPA method 21 or optical gas imaging (OGI) of thief hatches, closed vent systems, pumps, compressors, pressure relief devices, open-ended valves or lines, valves, flanges, connectors, piping, and associated equipment to identify leaking components at a frequency determined according to the following schedules:

(a) for ~~wellhead sites~~well production facilities or tank battery facilities:

(i) annually at facilities with a PTE less than 10~~two~~ tpy VOC;

(ii) semi-annually at facilities with a PTE equal to or greater than ~~two~~ 10 tpy and less than ~~five~~ 25 tpy VOC; and

(iii) quarterly at facilities with a PTE equal to or greater than ~~five~~ 25 tpy

(b) for gathering and boosting sites, gas processing plants, and transmission compressor stations

(i) ~~quarterly~~ semi-annually at facilities with a PTE less than 25 tpy VOC; and

(ii) ~~monthly~~ quarterly at facilities with a PTE equal to or greater than 25 tpy VOC

(4) Inspections using U.S. EPA method 21 shall meet the following requirements:

(a) the instrument shall be calibrated before each day of its use by the procedures specified in U.S. EPA method 21 and by the instrument manufacturer;

~~(b) the instrument shall be calibrated with zero air (less than 10 ppm of hydrocarbon in air), and a mixture of methane or n-hexane and air at a concentration near, but nor more than, 10,000 ppm methane or n-hexane; and~~

(~~c~~b) a leak is detected if the instrument records a measurement of 500 ppm or greater of hydrocarbon and the measurement is not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation.

(5) Inspections using OGI shall meet the following requirements:

(a) the instrument shall comply with the specifications, daily instrument checks, and leak survey requirements set forth in Subparagraphs (1) through (3) of Paragraph (i) of 40 CFR 60.18;

(b) a leak is detected if the emission images recorded by the OGI instrument are not associated with normal equipment operation, such as pneumatic device actuation or crank case ventilation.

(6) Leaks discovered pursuant to the leak detection methods of Paragraphs (3), (4) and (5) of Subsection C of 20.2.50.116 NMAC are not subject to enforcement by the department unless the owner or operator fails to perform the required repairs in accordance with Subsection E of 20.2.50.116 NMAC or keep required records in accordance with Subsection F of 20.2.50.116 NMAC.

(~~6~~7) Components that are difficult, unsafe, or inaccessible to monitor, as determined by the following conditions, are not required to be inspected until it becomes feasible to do so:

(a) difficult to monitor components are those that require elevating the monitoring personnel more than two meters above a supported surface. ~~or that cannot be reached via a wheeled scissor-lift or hydraulic type scaffold that allows access to components up to seven and six tenths meters (25 feet) above the ground;~~

(b) unsafe to monitor components are those that cannot be monitored without exposing monitoring personnel to an immediate danger as a consequence of completing the monitoring; and

(c) inaccessible to monitor components are those that are buried, insulated, or obstructed by equipment or piping that prevents access to the components by monitoring personnel.

Comment on 20.2.50.116(C): Redline required as the "and" here creates significant confusion where 112 is a default monthly inspection. It also conflicts with 112's statement that default is monthly unless otherwise stated in the specific rule section.

Ultimately, the reference is unnecessary when this leak program is a monitoring program.

Comment on 20.2.50.116(C)(1). (2): Redline required to align with OCD Waste Rule. As that rule and this one are focused on gas waste and gas related emissions, respectively, it is appropriate to apply flexibilities like this one based upon gas rate through the site.

Comment on 20.2.50.116(C)(1)(a): Redline required to limit to external AVO, and not requiring equipment to be opened up for internal inspection. AVO inspections can provide opportunities for operators to identify components at a facility that are not operating properly. The proposed language may be interpreted to require operators to open seals and gaskets to visually inspect for damage. This is not a common practice during an AVO inspection and may lead to unnecessary waste not typically associated with an AVO inspection. Incorporating this practice into an AVO inspection would also pose a safety issue when opening up the equipment to visually inspect for damage. Operators have specific practices, procedures, and guidelines for how and when to open equipment such as seals and gaskets to check for damage.

Comment on 20.2.50.116(C)(3)(a). The thresholds and inspection frequencies set in 20.2.50.116 C(3)(a) for requiring equipment leak surveys are unnecessarily stringent, result in less reductions than estimated, and impose unreasonable costs.

1. ***The ERG evaluation is flawed.*** The evaluation of VOC control quantities and costs, performed for NMED by ERG and presented in the ERG excel workbook titled “LDAR-Reductions-and-Costs-VOC-5-27-2021_erg-06-08-2021.xlsx” overstates the reductions that would be achieved by the rule and understates the costs of such reductions.
   a. ***Types of Survey Instrument and Reduction Percentages***. ERG assumes that companies would use an equal blend of Optical Gas Imaging (OGI) and Method 21 (handheld analyzer) instruments (500 ppm detection threshold) when doing surveys and averaged the reduction percentages for these two methods.
      i. Based on 2019 GHGRP reported survey types this is an incorrect assumption. Of 2,022 reported surveys, 1,714 (85%) were reported as using an OGI imaging instrument.
      ii. For this reason, NMOGA did not include Method 21 methodologies in any of their analyses.
   b. ***Model Plants – Well Production Facilities.*** The ERG analysis relied on a “model plant” that is not representative of New Mexico and does not represent the best data available.
      i. The ERG evaluation uses reductions and costs from the US EPA’s: Control Techniques Guidelines for the Oil and Natural Gas Industry. EPA-453/B-16-001. October 2016 [hereafter, "2016 CTG"]; U.S. Environmental Protection Agency, Office of Air and Radiation, Office of Air Quality Planning and Standards, Sector Policies and Programs Division Research Triangle Park, North Carolina Table 9-11 of the 2016 CTG. Specifically, ERG used reductions and costs from tables 9-11, 9-12, and 9-13 from the 2016 CTG’s to estimate reductions and costs for annual, semi-annual, and quarterly inspection frequencies at well production facilities (well sites)
      ii. These tables are based on “Model Plants” that EPA used to estimate potential emissions and reductions in the 2016 CTG’s
      iii. The “Model Plants” in the 2016 CTG’s were established by EPA for Natural Gas Well sites, Oil Well Sites with a GOR <300 scf/bbl, and Oil Well Sites with a GOR >= 300 scf/bbl. The counts of major equipment and components (valves, connectors, etc) for these model plants were based on information from an EPA/GRI study from 1996 (gas well sites) and 40 CFR Part 98, subpart W, Tables W-1B and W-1C (component counts for oil well sites). These EPA “Model Plants” represent a generic representation of well sites and are not specific to well sites in the San Juan and Permian Basins.
      iv. Based on equipment counts reported into the US EPA’s Greenhouse Gas Reporting Program (40 CFR Part 98, subpart W) well production facilities in the San Juan and Permian Basins have, on average, less pieces of major equipment, less components, and less potential equipment leak emissions than the 2016 CTG Model Plants. The GHGRP based well site Model Plants are reflective of San Juan and Permian Basin sites and should be used preferentially to the generic CTG models.
   c. ***Inaccurate Reductions – Well Production Facilities.*** The failure to rely on the correct model led to unrepresentative conclusions.
      i. Less potential for equipment leaks translates to less reductions from a leak detection and repair program. Comparing the ERG CTG based reduction estimates and the GHGRP based reduction estimates shows the effect of these differences.

Estimated Reductions Comparison - Tons Per Year VOC – OGI Surveys		
	ERG (CTG Basis)	NMOGA (GHGRP Basis)

	Gas Well Site	Oil Well Site <300 GOR	Oil Well Site <300 GOR	Gas Well Site	Oil Well Site <300 GOR	Oil Well Site <300 GOR
Annual	0.61	0.13	0.3	0.509	0.096	0.122
Semiannual	0.917	0.199	0.451	0.764	0.143	0.183
Quarterly	1.222	0.265	0.602	1.018	0.191	0.244

ii. Coupling these lower reductions with the costs in ERG's analysis workbook yields the following comparison of costs per ton of VOC reduction at the different survey frequencies in the proposed rule.

Costs of VOC Reductions - $ per ton of VOC reduced – OGI Surveys						
	ERG (CTG Basis)			**NMOGA (GHGRP Basis)**		
	Gas Well Site	**Oil Well Site <300 GOR**	**Oil Well Site <300 GOR**	**Gas Well Site**	**Oil Well Site <300 GOR**	**Oil Well Site <300 GOR**
Annual	$2,243	$10,343	$4,552	$2,686	$14,267	$11,226
Semiannual	$2,592	$11,954	$5,260	$3,124	$16,605	$12,975
Quarterly	$3,588	$16,553	$7,285	$4,299	$22,960	$17,973

iii. As this cost comparison table illustrates, by considering actual characteristics of well sites in the San Juan and Permian Basins rather than generic models based on old and non-specific data, the cost per ton of VOC reduction at well sites is meaningfully higher than projected by ERG.

d. ***Inaccurate Costs – Well production facilities.***

i. The costs used in the ERG analysis of 20.2.50.116 requirements for well sites are from the 2016 CTG's.

ii. In their December 2015 comments on the draft 2016 CTGs, the American Petroleum Institute (API) noted the estimated costs of leak surveys was significantly understated by EPA. The following excerpt from the API comments provide an overview of the costs underestimated by EPA.

EPA Did Not Consider Key Costs To Industry In Assessing The Cost Effectiveness Of Leak Detection Requirements Proposed.
In its cost analysis for the proposed control strategy for fugitives emissions, EPA did not adequately capture all of the costs associated with implementation of such a program. Specifically, in the cost-effectiveness evaluation, EPA underestimated the costs associated with:

- *Conducting leak surveys*
- *Completing repairs, and*
- *Maintaining the required recordkeeping, including the costs of developing and maintaining the corporate and site-specific monitoring plans.*

Further, EPA did not include several aspects beyond the cost of the actual survey work in its cost analysis, including:

- *Training of personnel*
- *Travel time and costs*
- *Equipment maintenance (e.g. monitoring device calibration)*

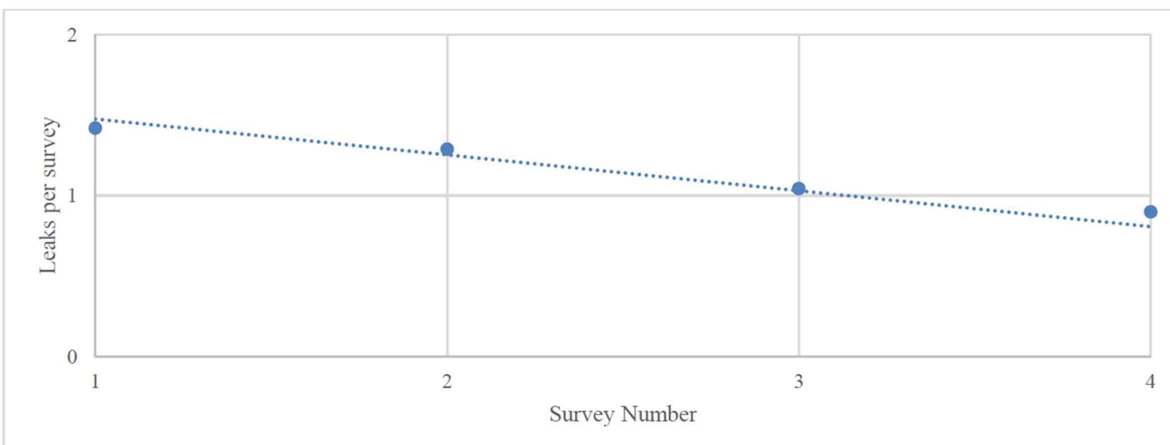
… Utilizing the more representative costs along with EPA's current estimates of emission reductions expected from the rule, the cost effectiveness of the proposed semi-annual OGI monitoring increases from EPA's estimate of $2,230 per well site to over $6,400 per site.

iii. Using the API cost of $6,400 per site with adjustment to a 2019 cost yields an estimated cost per ton of VOC reduction of $8,751 for the GHGRP based gas well site Model Plant and $7,253 for the 2016 CTG's gas well Model Plant.

iv. These additional costs support raising the monitoring thresholds to improve the feasibility of the rule.

2. ***Percent of components leaking, survey frequency and percent VOC reduction***
   a. In their December 17, 2018 comments to EPA regarding reconsideration of Subpart OOOOa (Docket ID No. EPA-HQ-OAR-2017-0483; EPA's "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration; Proposed Rule"; 83 Fed. Reg. 52056 (October 15, 2018)), the American Petroleum Institute (API) presented data from analysis of Subpart OOOOa leak surveys conducted by their member companies. API's analysis includes:
      i. Two years of Subpart OOOOa Leak Survey Data for Sites Monitored at a Semi-Annual Frequency
      ii. Over 6,000 total surveys across 3,482 sites
      iii. Represents data from 13 different operators
   b. API's analysis showed the following:
      i. There are large number of sites that have no leaks (58% of initial well site surveys).
      ii. The average number of leaking components per site is less than 2 components found leaking during the initial Subpart OOOOa survey and falls quickly to less than 1 leaking component found on average in subsequent surveys. These values are both below the 4 fugitive components that EPA assumed would require repair in each survey and even further below the number of leaks assumed in the EPA Leak Protocol Table 2-4 emission factors that were used to estimate emissions (See Figure 1 in Comment 1.1.3). In fact, nearly 92% of all surveys conducted across the 2-year period identified 4 or less leaking components per site.

Figure 1. Average Count of Leaks Found per Leak Survey Monitored per § 60.5397a



   c. Additionally, a research study funded by the API and conducted by GHD found an overall component leak percentage of 0.42% at 67 varied upstream oil and gas sites. This peer reviewed paper "Equipment leak detection and quantification at 67 oil and gas sites in the Western United States" was published in 2019. (Pacsi, Adam & Ferrara, Tom & Schwan, Kailin & Tupper, Paul & Lev-On, Miriam & Smith, Reid & Ritter, Karin. (2019). Equipment leak detection and quantification at 67 oil and gas sites in the Western United States. Elem Sci Anth. 7. 29. 10.1525/elementa.368.)
   d. This recent data further illustrates that the estimated VOC reductions in the 2016 CTG's used to evaluate 20.2.50.116 NMAC are overstated, the costs per ton of VOC reduction are higher, and the incremental reductions from increasing the frequency of leak surveys is lower than used in NMED's contractor's analysis.
   e. This further supports NMOGA's recommendation that less frequent leak surveys at higher emissions threshold are appropriate for wells and tank batteries.

Comment on 20.2.50.116(C)(3)(b). The emissions thresholds and associated leak monitoring frequencies at 20.2.50.116(C)(3)(b) are overly stringent and not supported by NMED's analysis. These thresholds and frequencies should be adjusted as indicated above to better reflect the potential reductions and costs of leak monitoring.

1. ***Gathering and Boosting Sites.***
   a. For gathering and boosting sites, ERG used reductions and costs from table 9-14 from the 2016 CTG to estimate reductions and costs for annual, semi-annual, and quarterly inspection frequencies at gathering and boosting sites. For the monthly inspection frequency case, ERM used the Colorado cost per inspection for

the annual cost. ERM then used the "CTG cost effectiveness value for quarterly OGI checks for G&B x a factor of 1.5 because the cost/ton increases as the frequency increases".

b. These tables are based on "Model Plants" that EPA used to estimate potential emissions and reductions in the 2016 CTG's

c. Similar to well production facilities, the "Model Plant" in the 2016 CTG, established by EPA for Gathering and Boosting sites major equipment and components (valves, connectors, etc), is based on old and limited information from an EPA/GRI study from 1996.

d. Based on a major recent study commissioned by the US Department of Energy and led by Colorado State University (Zimmerle, Daniel, Bennett, Kristine, Vaughn, Timothy, Luck, Ben, Lauderdale, Terri, Keen, Kindal, Harrison, Matthew, Marchese, Anthony, Williams, Laurie, & Allen, David. Characterization of Methane Emissions from Gathering Compressor Stations: Final Report. United States. https://doi.org/10.2172/1506681) gathering and boosting sites have, on average, less pieces of major equipment, less components, and less potential equipment leak emissions than the 2016 CTG Model Plant.

e. Less potential for equipment leaks translates to less reductions from a leak detection and repair program. Comparing the ERG CTG based reduction estimates and the CSU/DOE study-based reduction estimates shows the effect of these differences.

VOC Tons per Year Reduced per Gathering and Boosting Site			
OGI Inspection Frequency	**ERG Estimated**	**NMOGA Estimated**	
		San Juan	**Permian**
Annual	3.91	0.746	1.853
Semiannual	5.86	1.119	2.779
Quarterly	7.81	1.492	3.705
Monthly[a]	Not Shown	1.678	4.168
For the monthly OGI survey frequency, NMOGA used 90% reduction which is the Method 21 monthly reduction percentage stated by ERG minus the 2% differential for quarterly OGI surveys vs. quarterly Method 21 surveys.			

f. Using these more current and correct reduction estimates, NMOGA calculates the following costs per ton of VOC reductions for gathering and boosting sites in the San Juan basin and gathering and boosting sites in the Permian basin.

Cost per Ton of VOC Reduction - Gathering and Boosting Site		
OGI Inspection Frequency	**NMOGA Estimated**	
	San Juan	**Permian**
Annual	$10,837	$4,362
Semiannual	$12,572	$5,061
Quarterly	$17,452	$7,025
Monthly[a]	$46,539	$18,734
[a]The annual cost for monthly OGI surveys at G&B sites is the annual cost for quarterly surveys in ERG's workbook multiplied by 3 (12 surveys/4 surveys)		

g. The reductions are less and the costs higher in the San Juan basin than the Permian basin due to the differences in gas composition between the basins. The San Juan basin field gas is about 15% by weight VOC while the Permian basin field gas is about 31.8% by weight VOC.

h. As this analysis illustrates, the cost of leak surveys at gathering and boosting stations are significantly higher than estimated by ERG and not justified as currently proposed.
i. For these reasons, NMOGA recommends the frequencies and thresholds be adjusted to better reflect the potential reductions and costs.

2. Transmission Compressor Stations

a. In the analysis conducted for NMED, ERG did not include any information or basis for VOC emissions or VOC emission reductions from transmission compressor stations. ERG does state, in their analysis workbook, that they "Used Colorado cost per inspection for the annual cost and the CTG cost effectiveness value for quarterly OGI checks for G&B." for stations with a VOC PTE <25 tpy, and they "Used Colorado cost per inspection for the annual cost. Used the CTG cost effectiveness value for quarterly OGI checks for G&B x a factor of 1.5 because the cost/ton increases as the frequency increases." for stations with a VOC PTE >= 25 tpy.
b. Since there are no estimates of VOC emissions or emission reductions, there is no basis for NMOGA or the EIB to evaluate the efficacy of the 20.2.50.116 NMAC requirements for transmission compressor stations.
c. Given the fact that natural gas handled by transmission compressor stations has been processed and most propane and heavier hydrocarbons (VOC's) removed it is almost certain that potential equipment leak VOC emissions are very low and any reductions from LDAR surveys would be correspondingly very low.
d. The VOC content of typical pipeline natural gas in the US is around 0.8% by weight VOC, contrasted with 15% by weight for produced gas in the San Juan basin and 31.8% by weight for produced gas in the Permian basin.
e. EPA did not include transmission compressor stations in the 2016 CTG because, given the lack of VOCs in the gas handled, there is little to no potential for VOC reductions to be made at them.
f. Based on the EPA 2019 Greenhouse Gas Inventory and the typical composition of pipeline natural gas in the US, the equipment leak emissions of VOC are around 0.12 tpy per transmission compressor station. Reductions from LDAR leak surveys and repair are a fraction of this dependent on the survey frequency.
g. Due to the lack of information to evaluate the appropriateness of the proposed 20.2.50.116 NMAC for transmission compressor stations, the certainty that VOC emissions would be less than 0.1 tpy/station regardless of the inspection frequency, and the extremely high cost of the miniscule potential VOC reductions, NMOGA recommends that leak surveys for transmission compressor stations be reduced as outlined above.

3. ***Gas Processing Plants***

a. In their analysis, conducted for NMED, ERG does not document or analyze incremental VOC reductions from implementing 20.2.50.116 NMAC at gas processing plants.
b. ERG inappropriately uses the cost per ton of VOC reduction from the 2016 CTG to analyze the average cost per ton of reduction from gas processing plants. However, the basis for the 2016 CTG LDAR reductions and costs are entirely different than and not reflective of the requirements for LDAR at gas processing plants in 20.2.50.116.
    i. The 2016 CTG's evaluated the incremental reductions and costs of an existing gas plant moving from a Subpart KKK or Subpart VV LDAR program to a Subpart VVa program. The incremental requirements in the 2016 CTG's would be monthly checks for valves and pumps, and periodic checks for connectors based on the percent that are found leaking. If >0.5% of connectors are found leaking, then all need to be checked annually; longer intervals are allowed at lower percentages of leaking connectors.
    ii. In contrast, the requirements in 20.2.50.116 are for quarterly or monthly LDAR surveys of the entire gas processing facility rather than just incremental checks of valves and pumps.
    iii. ERG does acknowledge that most, if not all, gas processing plants in New Mexico are already implementing an LDAR program under Subpart KKK or Subpart VV. ERG also documents some plants subject to the Subpart OOOOa NSPS requirements for LDAR surveys which mirror those in the 2016 CTG's.
    iv. For gas processing plants that are already implementing a Subpart VVa program under NSPS OOOOa, ERG incorrectly assigns zero cost in their analysis. However, there are no exclusions of such plants in 20.2.50.116 NMAC as proposed. NMOGA has recommended a change in the proposed rule that acknowledges compliance with LDAR requirements in Subpart OOOOa, and other NSPS's constitutes compliance with 20.2.50.116 NMAC.
c. Without documentation of the incremental VOC reductions from implementing the proposed rule requirements at gas processing plants and correct documentation of the cost per ton of VOC reduction, there is no ability for NMOGA or the EIB to evaluate whether the requirements are appropriate or not.
d. For these reasons, NMOGA has recommended changes which would limit the frequency of LDAR surveys at

gas processing plants.

Comment on 20.2.50.116(C)(4)(a): Redline required as calibration procedures vary by type and manufacturer of instrument. This calibration requirement should cite the manufacturer's procedures.

Comment on 20.2.50.116(C)(7)(a): Redline required to align with federal rule. NMOGA finds language around scissor-lifts confusing and potentially asks operators to conduct unsafe work at unsafe heights. This practice is not routine and is done only when necessary, with significant safeguards. These safeguards, such as spotters and shutting in equipment, are generally not factored into cost-benefit and likely results in very little additional emissions reduction. Inspectors are regularly able to find leaks on top of storage tanks from the ground, without risking work at heights. To address these concerns we recommend removing language.

D. Alternative equipment leak monitoring plans: As an equivalent means of compliance with Subsection C of 20.2.50.116 NMAC, an owner or operator may comply with the equipment leak requirements through an alternative monitoring plan as follows:

(1) An owner or operator may comply with an individual alternative monitoring plan, subject to the following requirements:

(a) the proposed alternative monitoring plan shall be submitted to and approved by the department prior to conducting monitoring under that plan.

(b) the department may terminate an approved alternative monitoring plan if the department finds that the owner or operator failed to comply with a provision of the plan and failed to correct and disclose the violation to the department within 15 calendar days of ~~identifying~~ verifying the violation.

(c) upon department denial or termination of an approved alternative monitoring plan, the owner or operator shall comply with the default monitoring requirements under Subsection C of 20.2.50.116 NMAC within 15 days.

(2) An owner or operator may comply with a pre-approved monitoring plan maintained by the department, subject to the following requirements:

(a) the owner or operator shall notify the department of the intent to conduct monitoring under a pre-approved monitoring plan, and identify which pre-approved plan will be used, at least 15 days prior to conducting the first monitoring under that plan.

(b) the department may terminate the use of a pre-approved monitoring plan by the owner or operator if the department finds that the owner or operator failed to comply with the provision of the plan and failed to correct and disclose the violation to the department within 15 calendar days of identifying the violation.

(c) upon department denial or termination of an approved alternative monitoring plan, the owner or operator shall comply with the default monitoring requirements under of Subsection C of 20.2.50.116.C NMAC within 15 days.

Comment on 20.2.50.116(D)(2)(a): Redline required. Notice cannot be provided each time, but we can commit to notice the first time/first use. If the department wants to observe, they can reach out and operators can accommodate that request.

E. Repair requirements: For a leak detected pursuant to monitoring conducted under 20.2.50.116 NMAC:

(1) the owner or operator shall place a visible tag on the leaking component not otherwise repaired at the time of discovery until the component has been repaired;

(2) leaks shall be repaired within ~~15~~ 30 days of discovery~~, except for leaks detected using OGI, which shall be repaired within seven days of discovery;~~

(3) the equipment must be ~~re-monitored~~verified no later than 15 days after ~~discovery~~ repair of the leak to demonstrate that it has been repaired; ~~and~~

(4) if the leak cannot be repaired within ~~15~~ 30 days of discovery ~~, or within seven days for a leak detected using OGI,~~ without a process unit shutdown, the leak may be designated "Repair delayed," and must be repaired before the end of the next planned process unit shutdown~~.~~ and

(5) if the leak cannot be repaired within 30 days of discovery due to shortage of parts or personnel- , the leak may be designated "Repair delayed," and must be repaired within 15 days of resolution of such shortage.

Comment on 20.2.50.116(E)(2): Redline required because leak repair time should be consistent regardless of detection method.

Comment on 20.2.50.116(E)(3): Redline required: Verification of repair timeline should be tied to date of repair, not date of *discovery.*

Comment on 20.2.50.116(E)(5): Redline required due to supply chain restrictions. Below are some commentary and examples.
1. Oil and Gas companies do keep stock of some common sizes and parts for repairs and replacement. However, some fugitive emission components (or their associated parts) are not common stock and must be ordered at the time they are needed. The company is then potentially at the mercy of the distributor or manufacturer for receiving the part.
2. A valve leak was found and when maintenance went to repair, they could not. The valve was broken internally, and the valve was no longer available from the manufacturer (due to age). The piping and valve had to be re-engineered to accept a newer style/size of valve to fix the repair. This took time for Engineering to do and for Operations to implement.
3. Global Pandemic: The COVID-19 global pandemic created many stocking and manufacturing delays for parts across many sectors. Items once easily obtained became harder to source because manufacturers had reduced work.
4. 2021 Polar Vortex: The Winter storm that hit the Midwest and South in mid-February 2021 caused numerous shipping delays and operational issues for companies in the affected areas. Many companies were working diligently to maintain normal operations in the affected area.

F. Recordkeeping requirements:
(1) The owner or operator shall keep a record of the following for all AVO, RM21, OGI, or alternative equipment leak monitoring inspection conducted as required under 20.2.50.116 NMAC, and shall provide the record to the department upon request:
(a) facility location;
(b) date of inspection;
(c) monitoring method (e.g. AVO, RM 21, OGI, alternative method approved by the department);
(d) name of the ~~personnel~~ person(s) performing the inspection;
(e) a description of any leak requiring repair or a note that no leak was found; and
(f) whether a visible ~~flag~~ tag was placed on the leak or not;
(2) The owner or operator shall keep the following record for any leak that is detected:
(a) the date the leak is detected;
(b) the date of attempt to repair;
(c) for a leak with a designation of "repair delayed" the following shall be recorded:
(i) reason for delay if a leak is not repaired within the required number of days after discovery;
(ii) ~~signature of the authorized representative~~ name of person(s) who determined that the repair could not be implemented without a process unit shutdown or parts and/or personnel shortages;
(d) date of successful leak repair;
(e) date the leak was monitored after repair and the results of the monitoring; and
(f) a description of the component that is designated as difficult, unsafe, or inaccessible to monitor, an explanation stating why the component was so designated, and the schedule for repairing and monitoring the component.
(3) For a leak detected using OGI, the owner or operator shall keep records of the specifications, the daily instrument check, and the leak survey requirements specified at 40 CFR 60.18(i)(1)-(3).
(4) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.
G. Reporting requirements:
(1) The owner or operator shall certify the use of an alternative equipment leak monitoring plan under Subsection D of 20.2.50.116 NMAC to the department annually, if used.
(2) The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.
[20.2.50.116 NMAC - N, XX/XX/2021]

20.2.50.117 NATURAL GAS WELL LIQUID UNLOADING:
A. Applicability: Manual ~~L~~liquid unloading operations ~~including down-hole well maintenance events~~ resulting in the venting of natural gas at natural gas wells are subject to the requirements of 20.2.50.117 NMAC. Manual ~~L~~liquid unloading operations that do not result in the venting of any natural gas are not subject to this part. Within two years of the effective date of this Part, owners and operators of a Natural gas well subject to this Part, must comply with the standards set forth in Paragraph (3) of Subsection B of 20.2.50.117 NMAC.
B. Emission standards:
(1) The owner or operator of a natural gas well shall use best management practices during the life of the well to avoid the need for venting of natural gas associated with manual liquid unloading.
(2) The owner or operator of a natural gas well shall use the following best management practices

within two years of the effective date of this Part during venting associated with manual liquid unloading to minimize emissions, consistent with well site conditions and good ~~engineering~~ operating practices:

(a) reduce wellhead pressure before blowdown/venting to atmosphere;

(b) monitor manual venting associated with manual liquid unloading in close proximity to the well or via remote telemetry; and

(c) close ~~well head~~ vents to the atmosphere and return the well to normal production operation as soon as practicable.

(3) The owner or operator of a natural gas well shall employ methodologies to ~~use one of the following methods to~~ reduce emissions during venting associated with a liquid ~~n~~ unloading event. These methodologies may include, but are not limited to:

(a) ~~**(a)** installation and~~ use of a plunger lift

~~**(a)**~~**(b)** use of an automated controls system~~;~~

(~~b~~c) ~~installation and~~ use of ~~an~~ artificial lift ~~engine~~; or

(~~c~~d) ~~installation and~~ use of a control device.

~~**(4)** The owner or operator of a natural gas well shall install an EMT on the natural gas well in accordance with 20.2.50.112 NMAC.~~

C. Monitoring, inspection or testing requirements:

(1) The owner or operator shall monitor the following parameters during venting associated with manual liquid unloading:

(a) wellhead pressure;

(b) ~~flow rate of the vented natural gas (to the extent feasible)~~; and

(c) duration of venting to the ~~storage vessel~~tank battery or atmosphere.

(2) The owner or operator shall calculate the volume and mass of VOC emitted~~vented~~ during a venting event associated with a manual liquid unloading event.

~~(3) A liquid unloading event shall include the scanning of the EMT and monitoring data entry in accordance with the requirements of 20.2.50.112 NMAC.~~

~~(4)~~ (3) The owner or operator shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator shall keep the following records for manual liquid unloading:

(a) identification number and location of the well;

(b) date the liquid unloading was performed;

(c) wellhead pressure;

(d) flow rate of the vented natural gas (to the extent feasible). If not feasible, the owner or operator shall use the maximum potential flow rate in the emission calculation);

(e) duration of venting to the ~~storage vessel~~tank battery or atmosphere;

(f) a description of the management practice used to minimize venting and release of VOC emissions before and during the manual liquid unloading;

(g) the type of control device or control technique used to control VOC emissions during a venting associated with ~~the~~ a manual liquid unloading event; and

(h) a calculation of the VOC emissions vented during a venting associated with ~~-~~a manual ~~the~~liquid unloading event based on the duration, calculated volume, and ~~mass of VOC~~composition of the produced gas.

(2) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.117 NMAC - N, XX/XX/2021]

Comment on 20.2.50.117(A): Redline required as down-hole maintenance events (workovers) are covered in the workover portion of the proposed regulations and coverage here is redundant, will cause duplicative work, and is potentially confusing.

Comment on 20.2.50.117(B)(1): Redline required as the focus of this portion of the regulation needs to be ***venting*** *associated with liquid unloading not liquid unloading itself – i.e. managing the liquid loading in a well bore. This distinction is critical - there are a number of techniques and technologies used to manage well bore liquid loading that don't require or entail venting.*

Comment on 20.2.50.117(B)(2): Redline required to add phase in similar to other sections.

Comment on 20.2.50.117(B)(3): Redline required as there are numerous other techniques and technologies used to manage liquid loading. Velocity strings and soap/foaming agent injection are two examples. The predominant method of managing liquid loading is managing reservoir energy by use of shut-in periods to build reservoir energy and unload liquids into *production rather than venting.*

Comment on 20.2.50.117(C)(1)(b): Redline required as it is not feasible to measure or monitor the flow rate of vented natural gas except in a research setting. NMOGA suggests calculation techniques in the Green House Gas Reporting Rule. As support for using these, the UT 2015 research study, which measured venting, concluded that their measurements compared favorably with the calculated volumes using the GHGRP methodologies.

20.2.50.118 GLYCOL DEHYDRATORS:

A. Applicability: Glycol dehydrators with a PTE equal to or greater than two tpy of VOC and having an actual annual average flowrate of natural gas to the glycol dehydration units of greater than 3 MMscfd ~~and~~located at ~~wellhead sites~~well production facilities, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations are subject to the requirements of 20.2.50.118 NMAC.

Comment on 20.2.50.118.A: Redlined required to align 20.2.50.118 threshold for regulation with the threshold under 40 CFR Part 63, Subpart HH for the more stringent standards applicable to large glycol dehydration units. Imposing the emissions standards under 20.2.50.118.B to small glycol dehydration units is not warranted given the minimal emissions expected from units of this size.

B. Emission standards:

(1) Existing glycol dehydrators with a PTE equal to or greater than two tpy of VOC shall achieve a minimum combined capture and control efficiency of ninety-five percent of VOC emissions from the still vent and flash tank, where present, no later than two years after the effective date.
If a combustion control device is used, the combustion control device shall have a minimum design combustion efficiency of ninety-eight percent.

(2) New glycol dehydrators with a PTE equal to or greater than two tpy of VOC shall achieve a minimum combined capture and control efficiency of ninety-five percent of VOC emissions from the still vent and flash tank, where present, upon startup.
If a combustion control device is used, the combustion control device shall have a minimum design combustion efficiency of ninety-eight percent.

(3) The owner or operator of a glycol dehydrator shall comply with the following requirements:

(a) still vent and flash tank emissions shall be routed at all times to the reboiler firebox, condenser, combustion control device, fuel cell, to a process point that either recycles or recompresses the emissions or uses the emissions as fuel, or to a VRU or VRCU that reinjects the VOC emissions back into the process stream or natural gas gathering pipeline;

(b) if a VRCU is used, it shall consist of a closed loop system of seals, ducts and a compressor that reinjects the vapor~~natural gas~~ into the process or the natural gas pipeline. The VRCU shall be operational at least ninety-five percent of the time the facility is in operation, resulting in a minimum combined capture and control efficiency of ninety-five percent, which shall supersede any inconsistent requirements in 20.2.50.115 NMAC. The VRCU shall be installed, operated, and maintained according to the manufacturer's specifications;

(c) still vent and flash tank emissions shall not be vented directly to the atmosphere during normal operation; and

~~**(d)** the owner or operator of a glycol dehydrator shall install an EMT on the glycol dehydrator in accordance with 20.2.50.112 NMAC.~~

(4) an owner or operator complying with the requirements in Subsection B of 20.2.50.118 NMAC through use of a control device shall comply with the requirements in 20.2.50.115 NMAC.

(5) The requirements of Subsection B of 20.2.50.118 NMAC cease to apply when the ~~uncontrolled~~ actual annual VOC emissions from a new or existing glycol dehydrator are less than two tpy VOC.

C. Monitoring, inspection or testing requirements:

(1) The owner or operator of a glycol dehydrator shall conduct an annual extended gas analysis on the dehydrator inlet gas and calculate the uncontrolled and controlled VOC emissions in tpy. A representative gas analysis may be utilized for this calculation.

(2) The owner or operator of a glycol dehydrator shall inspect the glycol dehydrator, including the reboiler and regenerator, and the control device or process the emissions are being routed, semi- annually to ensure it is operating as initially designed and in accordance with the manufacturer recommended operation and maintenance schedule.

(3) An owner or operator complying with the requirements in Subsection B of 20.2.50.118 NMAC through the use of a control device shall comply with the monitoring, inspection or testing requirements in 20.2.50.115 NMAC.

(4) Owners and operators shall comply with the monitoring, inspection or testing requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator of a glycol dehydrator shall maintain a record of the following:

(a) dehydrator location and identification number;

(b) glycol circulation rate, monthly natural gas throughput, and the date of the most recent throughput measurement;

(c) data and methodology used to estimate the PTE of VOC (must be a department approved calculation methodology);

(d) amount of controlled and uncontrolled VOC emissions in tpy;

(e) type, make, model, and identification number of the control device or process the emissions are being routed;

(f) date and results of any equipment inspection, including maintenance or repair activities required to bring the glycol dehydrator into compliance; and

(g) a copy of the glycol dehydrator manufacturer operation and maintenance recommendations, when available and applicable.

(2) An owner or operator complying with the requirements in Paragraph (1) or (2) of Subsection B of 20.2.50.118 NMAC through use of a control device as defined in this Part shall comply with the recordkeeping requirements in 20.2.50.115 NMAC.

(3) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.118 NMAC - N, XX/XX/2021]

Comment on 20.2.50.118(B)(3)(c): Redline required. Under 20.2.50.118.B(3)(c), "the still vent and flash tank emissions shall not be vented to the atmosphere." At the same time, under 20.2.50.118.(B)(3)(b) a Vapor Recovery Control Unit is permitted 5% downtime. NMOGA is concerned these statements may be inconsistent in practice if the venting prohibition is applied too broadly to prohibit unavoidable releases inherent in the industry's processes. For example, common releases that will consume the 5% downtime include emissions from periods of startup or shutdown, emissions vented via air pollution control equipment to the atmosphere, or other emissions during periods of startup for certain types of air pollution control equipment (e.g., thermal oxidizers). The rule should make clear that these unavoidable releases are not prohibited under the venting prohibition.

For these reasons, NMOGA recommends the department remove the venting prohibition altogether. Alternatively, NMED should clarify the scope of the venting concept and revise the venting prohibition to only require controls during normal operations. NMOGA requests the following revision to 20.2.50.18.B(3)(c).

Comment on 20.2.50.118(B)(5): Redline required because actual emissions offramps should be based on what is actually emitted, regardless of whether those emissions are released from a controlled or uncontrolled emissions unit. Glycol dehydrators may be controlled pursuant to other legal requirements (e.g., 40 C.F.R. Part 63, Subpart HH), and operators should be authorized to take these controls into account when quantifying actual emissions for purposes of exiting 20.2.50.118 NMAC.

Comment on 20.2.50.118(C)(1): Redline required as conducting an extended gas analysis as required in 20.2.50.18.C(1) on the inlet of each glycol dehydrator increases compliance costs to the owners and operators without providing any reduction in emissions. NMED should allow representative extended analyses to be used in lieu of glycol dehydrator-specific inlet analyses. Under this approach, owners and operators would conduct a gas analysis on a representative inlet and apply this concentration to other units that, within the engineering judgment of the source, would exhibit comparable characteristics.

Comment on 20.2.50.118(D)(1)(g): Redline required because the current rule does not account for numerous scenarios where manufacturer's recommended schedules for maintenance and repair may not be available or be practical for the current operating scenario. Glycol dehydrators often have useful service lives that extend beyond a single site. As a result, the initial design and manufacturer's recommendations may not be appropriate in the new operating scenario. Additionally, documentation may not be available for older units. If this is not removed from the regulation there will be equipment that cannot meet this requirement and will continually be out of compliance with this requirement. NMED must allow owners and operators to develop maintenance and operating procedures based on site-specific factors and industry's extensive experience operating this type of equipment.

20.2.50.119 HEATERS:

A. Applicability: Natural gas-fired heaters with a rated heat input equal to or greater than 10 MMBtu/hour including heater treaters, heated flash separators, evaporator units, fractionation column heaters, and glycol dehydrator reboilers in use at ~~wellhead sites~~well production facilities, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations are subject to the requirements of 20.2.50.119 NMAC.

B. Emission standards:

(1) Natural gas-fired heaters shall comply with the emission limits in table 1 of 20.2.50.119 NMAC.

Table 1 - EMISSION STANDARDS FOR NO_X AND CO

Date of Construction:	NO_X (ppmvd @ 3% O_2)	~~CO (ppmvd @ 3% O2)~~
Constructed or reconstructed before the effective date of 20.2.50 NMAC	30	~~300~~
Constructed or reconstructed on or after the effective date of 20.2.50 NMAC	30	~~130~~

(2) Existing natural gas-fired heaters shall comply with the requirements of 20.2.50.119 NMAC no later than ~~one~~ three years after the effective date of this Part.

(3) New natural gas-fired heaters shall comply with the requirements of 20.2.50.119 NMAC upon startup.

C. Monitoring, inspection and testing requirements:

(1) The owner or operator shall:

(a) conduct emission testing for NOx and CO within 180 days of the compliance date specified in Paragraph (2) or (3) of Subsection B of 20.2.50.119 NMAC and at least every two years thereafter.

(b) inspect, maintain, and repair the heater in accordance with the manufacturer specifications at least once every two years following the applicable compliance date specified in 20.2.50.119 NMAC. The inspection, maintenance, and repair shall include the following:

(i) inspecting the burner and cleaning or replacing components of the burner as necessary;

(ii) inspecting the flame pattern and adjusting the burner as necessary to optimize the flame pattern consistent with the manufacturer specifications, if available and good ~~engineering~~ operational practices;

(iii) inspecting the AFR controller and ensuring it is calibrated and functioning properly, if such as system is installed on the heater;

(iv) optimizing total emissions of CO consistent with the NOx requirement, manufacturer specifications, if available, and good combustion ~~engineering~~ operational practices; and

(v) measuring the concentrations in the effluent stream of CO in ppmvd and O2 in volume percent before and after adjustments are made in accordance with Subparagraph (c) of Paragraph (2) of Subsection C of 20.2.50.119 NMAC.

(2) The owner or operator shall comply with the following periodic testing requirements:

(a) conduct three test runs of at least 20-minutes duration at highest achievable load ~~within ten percent of one-hundred percent peak, or the highest achievable, load~~;

(b) determine NOX and CO emissions and O2 concentrations in the exhaust with a portable analyzer used and maintained in accordance with the manufacturer specifications and following the procedures specified in the current version of ASTM D6522;

(c) if the measured NOX or CO emissions concentrations are exceeding the emissions limits of table 1 of 20.2.50.119 NMAC, the owner or operator shall repeat the inspection and tune-up in Subparagraph (b) of Paragraph (1) of Subsection C of 20.2.50.119 NMAC within 30 days of the periodic testing; and

(d) if at any time the heater is operated in excess of the highest achievable load in a prior test plus ten percent , the owner or operator shall perform the testing specified in Subparagraph (a) of Paragraph (2) of Subsection C of 20.2.50.119 NMAC within 60 days from the anomalous operation.

(3) When conducting periodic testing of a heater, the owner or operator shall follow the procedures in Paragraph (2) of Subsection C of 20.2.50.119 NMAC. An owner or operator may deviate from those procedures by submitting a written request to use an alternative procedure to the department at least 60 days before performing the periodic testing. In the alternative procedure request, the owner or operator must demonstrate the alternative procedure's equivalence to the standard procedure. The owner or operator must receive written approval from the department prior to conducting the periodic testing using an alternative procedure.

~~**(4)** Prior to a monitoring, inspection, maintenance, or repair event, the owner or operator shall scan the EMT and the required monitoring data shall be captured in accordance with this Part.~~

D. Recordkeeping requirements: The owner or operator shall maintain a record of the following:

(1) location of the heater;

(2) summary of the complete test report and the results of periodic testing; and

(3) inspections, testing, maintenance, and repairs, which shall include at a minimum:

(a) the date the inspection, testing, maintenance, or repair was conducted;
(b) name of the person(s) ~~personnel~~ conducting the inspection, testing, maintenance, or repair;
(c) concentrations in the effluent stream of CO in ppmv and O2 in volume percent; and
(d) the results of the inspections and any the corrective action taken.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.
[20.2.50.119 NMAC - N, XX/XX/2021]

Comment on 20.2.50.119(B)(1), Table 1: Redline required to remove the CO emission limit, as CO is not a precursor to ozone.

Comment on 20.2.50.119(B)(2): Redline required as more time will be needed for the large heaters at processing plants to design the change, budget for the upgraded equipment, procure the equipment and schedule the equipment downtime to minimize plant or upstream flaring events.

Comment on 20.2.50.119(C)(1)(b)(ii): Redline required in the event that manufacturer specifications are not available.

Comment on 20.2.50.119(C)(1)(b)(ii), (iv). Redlined required to change engineering to operational to reflect the fact that operational employees are generally in the best position to understand field operation of equipment.

Comment on 20.2.50.119(C)(1)(b)(iii): Redline required as some units do not have an AFR controller.

Comment on 20.2.50.119(C)(2)(a): Redline is required as heater tests should only be required to verify their emission limits at the highest achievable capacity during the test. Conditions may include insufficient fuel gas, fuel gas heat content, ambient conditions, etc. In addition, potential safety concern exists if testing team can run inlet fuel gas pressure higher (with no overpressure protection) than heater nameplate.

Comment on 20.2.50.119(C)(2)(d): Redline is required for alignment with comment above [20.2.50.119(C)(2)(a)].

Comment on 20.2.50.119(C)(4). Redlined required to align with removal of EMT requirement to scan prior to monitoring events.

20.2.50.120 HYDROCARBON LIQUID TRANSFERS:

A. Applicability: Hydrocarbon liquid transfers located at ~~wellhead sites~~well production facilities, tank batteries, gathering and boosting sites, natural gas processing plants, or transmission compressor stations except as noted below in this section are subject to the requirements of 20.2.50.120 NMAC beginning three ~~one~~ year(s) from the effective date of this Part. Tank batteries, gathering and boosting sites, natural gas processing plants or transmission compressor stations, any of which are connected to oil sales pipelines that are routinely used for hydrocarbon liquid transfer, are not subject to the requirements of 20.2.50.120. Tank batteries, gathering and boosting sites, natural gas processing plants or transmission compressor stations that load out hydrocarbon liquids to trucks fewer than thirteen (13) times in a calendar year are not subject to 20.50.2.120.

Comment on 20.2.50.120(A): Redline required to align with storage vessel requirements as retrofit of storage vessel and liquid transfer would be concurrent. This exemption will better serve the ends of the rule—to reduce VOC emissions through application of reasonably available, economically feasible controls—and will mitigate safety concerns for low flow loading occurring at liquid transfer operations. Establishing a fewer than 13 loadouts per calendar year applicability threshold and only applying this rule where oil transfers to sales through connected oil pipelines are expected except for very rare pipeline outages ensures that the stringent 98% control requirement would not be applied where minimal emissions reduction benefit will be realized. Installing such costly controls when they will be used only in emergency/upset conditions or the equivalent of once per month is economically infeasible for these smaller units from a cost-per-ton perspective. From a safety perspective, when conveying waste gas to a combustor in a low flow loading operation, the introduction of ambient air to process vessels through infiltration or forced/induced draft would create an explosion hazard. These high volumes of air introduce excess oxygen into the process or existing vapor controls for rich gas streams, creating a potentially explosive environment in the process and a risk of fire or explosion. Further, excess oxygen exacerbates corrosion and presents risks of potential loss of primary containment.

B. Emission standards:

(1) The owner or operator of a hydrocarbon liquid transfer operation shall use vapor balance or a control device designed to control VOC emissions by at least ninety-~~eight~~ five percent when transferring hydrocarbon liquid from a storage vessel to a tanker truck or tanker rail car for transport~~transfer vessel, or when transferring liquid from a transfer vessel to a storage vessel~~.

(2) ~~An owner or operator~~The personnel conducting the hydrocarbon liquid transfer operation using vapor balance ~~during a liquid transfer operation~~ shall:

(a) transfer the vapor displaced from the tanker truck or rail car ~~vessel~~ being loaded back to the storage vessel being emptied via a pipe or hose connected before the start of the transfer operation. If multiple storage vessels are vapor manifolded together in a tank battery, then the vapor may be routed back to any storage vessel in the tank battery;

(b) ensure that the transfer does not begin until the vapor collection and return system is properly connected;

(c) ~~ensure that~~inspect connector pipes, hoses, couplers, valves, and pressure relief devices for leaks;

~~are maintained in a leak-free condition;~~

(d) check the hydrocarbon liquid and vapor line connections for proper connections before commencing the transfer operation; and

(e) operate transfer equipment at a pressure that is less than the pressure relief valve setting of the receiving transport vehicle or storage vessel.

~~(3) Bottom loading or submerged filling shall be used for the liquid transfer.~~

(4) Connector pipes and couplers shall be______________ inspected for leaks~~maintained in a leak-free condition~~.

(5) Connections of hoses and pipes used during hydrocarbon liquid transfer operations shall be supported on drip trays that collect any leaks, and the materials collected shall be returned to the process or disposed of in a manner compliant with state law.

(6) Liquid leaks that occur shall be cleaned and disposed of in a manner that ~~prevents~~ minimizes emissions to the atmosphere, and the material collected shall be returned to the process or disposed of in a manner compliant with state law.

(7) An owner or operator complying with Paragraph (1) of Subsection B of 20.2.50.120 NMAC through use of a control device shall comply with the control device requirements in 20.2.50.115 NMAC.

Comment on 20.2.50.120(B)(1): The proposed 98% destruction efficiency and controls are more stringent than similar provisions promulgated in nonattainment areas or under more stringent control technology standards and cannot be achieved on a continuous basis. For example, the FIP for the Uintah Basin ozone nonattainment area did not impose a control efficiency requirement and merely stipulated that tank trucks must be loaded using bottom filling or a submerged fill pipe. 85 Fed. Reg. at 3532. Similarly, Utah conducted a "Best Available Control Technology" review for tank truck loading of hydrocarbon liquids and only imposed a 95% VOC destruction efficiency and a bottom filling or a submerged fill pipe requirement. U.A.C. R307-504-4.

NMOGA also believes the requested revisions are reasonable because they are consistent with design requirements for other equipment subject to this rule. For example, NMED has determined that 95% control is appropriate for storage tanks with a potential to emit between 2-10 TPY, an emissions range that is consistent with the potential emissions of many hydrocarbon liquid transfer operations. Hydrocarbon liquid transfers may be required during infrequent, non-routine operating scenarios. For example, LACT downtime may lead to emergency hydrocarbon liquid transfers. Similarly, hydrocarbon liquid transfers may be required during infrequent condensate loads at compressor stations where flares may not otherwise be present. In these scenarios, adding a vent to combustion or vapor balance is not cost effective. NMOGA requests that such operations be exempted from the control requirements in 20.2.50.20.B or that NMED set an appropriate threshold for applicability. Vapor recovery would introduce oxygen to the product stream and potentially not meet sales specifications. This would require shut-ins or flaring, ultimately creating emission events. Adding bottom loading or submerged filling allows for additional options to meet the emissions reductions.

NMOGA has also clarified that the 95% control efficiency requirement should be based on control device design. This change is made to ensure consistency with section 20.2.50.115.B.2, which requires that control devices be "adequately designed and sized to achieve the control efficiency rates required."

Comment on 20.2.50.120(B)(2)(a): Redline required for when multiple tank vapor spaces are manifolded and adequately communicating vapor space, vapor may be returned to any one of the tanks or to the vapor header.

Comment on 20.2.50.120(B)(3): If control with control device or vapor balance maintains the 95%, this adds no additional value.

Comment on 20.2.50.120(B)(6): Redline required as it is impossible to clean up a leak in a manner that prevents all emissions to the atmosphere. By definition, a leak means that the liquid is exposed to atmosphere and will volatilize.

C. Monitoring requirements:

(1) The owner or operator or their designated representative shall visually inspect the hydrocarbon liquid transfer equipment monthly at staffed locations or semiannually for unstaffed locations ~~during a transfer operation~~ to ensure that hydrocarbon liquid transfer lines, hoses, couplings, valves, and pipes are not dripping or leaking. Leaking components shall be repaired to prevent dripping or leaking before the next transfer operation or proper measures must be implemented to mitigate leaks until the necessary repairs can be completed.

(2) The owner or operator of a liquid transfer operation controlled by a control device must follow manufacturer recommended operation and maintenance procedures for the device.

~~(3) Tanker trucks and tanker rail cars used in liquid transfer service shall be tested annually for vapor tightness in accordance with the following test methods and vapor tightness standards:~~

~~(a) method 27 of appendix A of 40 CFR Part 60. Conduct the test using a time period (t) for the pressure and vacuum tests of five minutes. The initial pressure (Pi) for the pressure test shall be 460 mm H2O (18 inches H2O), gauge. The initial vacuum (Vi) for the vacuum test shall be 150 mm H2O (six inches H2O) gauge. The maximum allowable pressure and vacuum changes (Δp, Δv) are shown in table 1 of 20.2.50.120 NMAC.~~

~~Table 1 - ALLOWABLE CARGO TANK TEST PRESSURE OR VACUUM CHANGE~~

~~Cargo tank or compartment capacity, liters (gallons)~~	~~Allowable vacuum change (Δv) in five minutes, mm H2O (inches H2O)~~	~~Allowable pressure change (Δp) in five minutes, mm H2O (inches H2O)~~
~~< 3,785 (< 1,000)~~	~~64 (2.5)~~	~~102 (4.0)~~
~~3,785 < 5,678 (1,000 < 1,500)~~	~~51 (2.0)~~	~~89 (3.5)~~
~~5,678 < 9,464 (1,500 < 2,500)~~	~~38 (1.5)~~	~~76 (3.0)~~
~~> 9,464 (> 2,500)~~	~~25 (1.0)~~	~~64 (2.5)~~

~~(b) pressure test the tanker truck or tanker railcar tank's internal vapor valve as~~

~~(i) after completing the tests under Subparagraph (a) of Paragraph (3) of Subsection C of 20.2.50.120 NMAC, use the procedures in method 27 to re-pressurize the tank to 460 mm H2O (18 inches H2O) gauge. Close the tank's internal vapor valve, thereby isolating the vapor return line and manifold from the tank.~~

~~(ii) relieve the pressure in the vapor return line to atmospheric pressure, then reseal the line. After five minutes, record the gauge pressure in the vapor return line and manifold. The maximum allowable five-minute pressure increase is 130 mm H2O (five inches H2O).~~

(3~~4~~) Owners and operators complying with Paragraph (1) of Subsection B of 20.2.50.120 NMAC through use of a control device shall comply with the monitoring requirements in 20.2.50.115 NMAC.

(4~~5~~) Owners and operators shall comply with the monitoring requirements in 20.2.50.112 NMAC.

Comment on 20.2.50.120(C)(1): Redline required as monitoring requirements in C(1) are redundant with AVO provisions in 20.2.50.116C(2)(a). Further, C(1) implies that inspections must occur during every loading event. However, this is not practicable as some facilities may not be staffed during all hydrocarbon liquid transfer operations. If it is NMED's intent to require inspections during loading events, NMOGA requests that a more reasonable inspection frequency be established. NMOGA believes a monthly visual inspection for staffed locations and a semiannual visual inspection for unstaffed locations would be appropriate. While NMOGA members can take measures to prevent leaks from reoccurring, a permanent fix may not be feasible or realistic before the next transfer operations. However, NMOGA members may be able to implement certain measures to mitigate the leaks until a permanent fix can be implemented.

Comment on 20.2.50.120(C)(2): Consistent with the General Comments, NMOGA has concerns about manufacturer specifications. While operators strive to establish appropriate operating, maintenance, and repair procedures, we may learn through our unique operating experience with the equipment that something different than the manufacturer's specifications should be followed. Furthermore, small details in manufacturer's specifications should not be enforceable regulatory requirements. If this provision is retained, NMOGA requests that it be given flexibility to revise these specifications based on its experience with the equipment.

Comment on 20.2.50.120(C)(3): These requirements impose testing requirements on pieces of equipment (i.e. tank trucks) that are not owned or operated by upstream oil and gas producers and are not stationary sources. While NMOGA would support a vapor tightness recordkeeping requirement, it is not appropriate to impose vapor tightness performance standards on oil and gas operators who do not own or operate these pieces of equipment. NMED is also preempted from imposing these standards *under 49 U.S.C. § 5125(b) and 49 U.S.C. § 10501(b).*

NMOGA has struck this language consistent with NMED Exhibit 41.

D. Recordkeeping requirements:

~~(1) The owner or operator shall maintain a record of the location of the storage vessel and if using a control device, the type, make, and model of the control device:~~

(~~2~~1) The owner or operator shall maintain a record of the inspections and testing required for equipment they own and operate in Subsection C of 20.2.50.120 NMAC and shall include the following:

(a) the time and date of the inspection and testing;

(b) the name of the ~~personnel~~ person(s) conducting the inspection and testing;

(c) a description of any problem observed during the inspection and testing; and

(d) the results of the inspection and testing and a description of any repair or corrective action taken.

~~(3) The owner or operator shall maintain a record for each site of the annual total hydrocarbon liquid transferred and annual total VOC emissions. Each calendar year, the owner or operator shall create a company-wide record summarizing the annual total hydrocarbon liquid transferred and the annual total~~

(~~4~~2) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

Comment on 20.2.50.120(D)(1): Redline required as it is duplicative with storage tank requirements. Redline required as NMED has yet to provide any cost benefit information regarding the estimated reduction in ozone precursors that will be gained by implementing this part.

Comment on 20.2.50.120(D)(2): Redline required as owners and operators should not be required to maintain records of testing conducted on equipment they do not own or operate.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.
[20.2.50.120 NMAC - N, XX/XX/2021]

20.2.50.121 PIG LAUNCHING AND RECEIVING:

Comment on 20.2.50.121. NMOGA requests removal of the proposed pig launching and receiving provisions. NMOGA does not believe these standards are justified considering the minimal emissions reductions predicted and the technological and economic feasibility issues anticipated. Illustratively, EPA's Control Techniques Guideline (CTG) evaluation does not recommend standards for pig launching and receiving. In explaining the sources selected for EPA's 2016 review, the agency explained, "[t]hese sources were selected for RACT recommendations because current information indicates that they are significant sources of VOC emissions." NMOGA concurs with EPA that pig launching and receiving are not generally significant sources of VOC emissions and imposition of controls is not warranted. Although the CTG review took place in 2016, the emissions profile for these sources has not changed, and NMED's analysis does not justify a conclusion different than the one reached by EPA. In fact, according to NMED's own data supporting this rule, VOC emissions from pig launching and receiving are a scant 0.2 TPY, and VOC emissions will not be reduced as a result of the rule. While this analysis is questionable, it does not support the controls proposed. And although there has been an enforcement focus on pig launching and receiving from EPA, the alleged violations have largely focused on operators' failure to properly account for pig launching and receiving in their permitting activities. This focus does not reflect a revised belief that controlling pig launching and receiving is necessary to reduce ozone concentrations, as NMED's rule is intended to do. What is more telling is EPA's 2020 federal implementation plan proposal for the Uintah Basin nonattainment area, 85 Fed. Reg. 3492 (Jan. 21, 2020), in which EPA did not propose any standards for pig launching and receiving. This stance is consistent with EPA's 2016 CTG and NMED's own analysis. Finally, although controls on pig launching and receiving have been implemented in limited contexts in other areas of the country, NMED has not fully vetted the challenges for implementing these approaches in a state like New Mexico where sites are remote and lack infrastructure. For example, NMED has not evaluated whether requiring control of remote pigging operations would have a negative net effect on ozone concentrations because of NOx emissions from the additional transport of personnel and equipment. While NMOGA urges NMED to remove these provisions, if NMED elects to retain them, NMOGA has several suggestions for improvement.

A. Applicability: Individual p~~P~~ipeline pig launchers~~ing~~ and/or receivers ~~ing operations~~ with a PTE greater than or equal to one tpy VOC located within ~~or outside of~~ the property boundary of ~~wellhead sites~~well production facilities, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations are subject to the requirements of 20.2.50.121 NMAC. -

Comment on 20.2.50.121(A): Redline required to eliminate applicability to off-facility pigging operations and operations with potential emissions less than 1 TPY. Pigging is a small source of VOCs. Since NMED's model shows that ozone is NOx limited, controlling pig traps with NOx-producing combustion will not have the desired ozone impact. This is particularly true where the emissions potential from the operation is minimal or pigging takes place outside facility locations, a process that requires additional generation of NOx from the use of portable flares and trucks for transporting controls and personnel.

B. Emission standards:

(1) Owners and operators of affected pipeline pig launchers~~ing and~~ or receivers~~ing operations~~ ~~with a PTE equal to or greater than one tpy of VOC~~ shall route emissions to process or to a device designed to achieve a 95% destruction efficiency for c~~apture and reduce~~ VOC emissions from pigging operations ~~by at least ninety-eight~~ ~~percent~~ ,within 3 years of ~~beginning on~~ the effective date of this Part. Where it is infeasible to route to process, this requirement shall not require a control device that requires supplemental fuel to achieve destruction.

(2) The owner or operator conducting an affected ~~the~~ pig launching and/or receiving operation shall:

(a) employ best management practices to minimize the liquid present in the pig receiver chamber and to minimize~~prevent~~ emissions from the pig receiver chamber to the atmosphere after receiving the pig in the receiving chamber and before opening the receiving chamber to the atmosphere;

(b) employ a method to ~~prevent~~ minimize emissions, such as installing a liquid ramp or drain, routing a high-pressure chamber to a low-pressure line or vessel, using a ball valve type chamber, or using multiple pig chambers;

(c) recover and dispose of receiver liquid in a manner that ~~prevents~~ minimizes emissions to the atmosphere to the extent practicable; and

(d) ensure that the material collected is returned to the process or disposed of in a manner compliant with state law.

(3) The emission standards in Paragraphs (1) and (2) of Subsection B of 20.2.50.121 NMAC cease to apply to ~~a pipeline pig launching and receiving operation~~ an individual pipeline pig launcher and/or receiver if the uncontrolled actual annual VOC emissions of the ~~operation~~ launcher or receiver are less than one ton per year of VOC.

(4) An owner or operator complying with Paragraph (2) of Subsection B of 20.2.50.121 NMAC through use of a non-portable control device shall comply with the control device requirements in 20.2.50.115 NMAC. An owner or operator complying through use of a portable control device shall install the device consistent with manufacturer's specifications and is not subject to the requirements of 20.2.50.115 NMAC .

Comment on 20.2.50.121(B)(2)(c): Redline required because, while NMOGA agrees that emissions can be minimized through proper recovery of receiver liquids, fugitive emissions that are impractical to prevent will occur.

Comment on 20.2.50.121(B)(3): Redlined required to clarify that the 1 TPY threshold should be calculated based on the emissions potential of a single pig launcher or receiver.

Comment on 20.2.50.121(B)(4). Redline required because portable devices available to buy or to rent on the market may not have all the monitoring capability that can be installed on fixed equipment. It is not obvious whether these portable devices can be altered to meet all the monitoring requirements and furthermore, in the case of using rental control devices that may be used to control infrequent pig launching and receiving emissions, rental companies will not want their rental equipment to be altered by the company renting it. The proposed language resolves this concern. By installing the portable device consistent with manufacturer's specifications, the equipment will be used in the optimal manner per its manufacture and design, and it will not require additional appurtenances that may not be able to be installed.

C. Monitoring, testing and inspection requirements:

~~**(1)** The owner or operator of pig launching and receiving operations shall monitor the type and volume of liquid cleared.~~

(~~2~~1) The owner or operator of an affected pig launching and receiving ~~operations~~ site shall inspect the equipment for ~~a~~ leaks using either AVO, RM 21, or OGI on either:

(a) a monthly basis if pigging operations at a site occur on a monthly basis or more frequently; or

(b) prior to the commencement and ~~immediately before the commencement and immediately~~ after the conclusion of the pig launching or receiving operation, if less frequent.

(2) The monitoring procedures shall be performed using the methodologies outlined ~~in accordance with the requirements~~ in Paragraphs (2) through (4)) of Subsection (C) of 20.2.50.116 NMAC as applicable, and at the frequency outlined in Paragraph (1) of Subsection (C) of 20.2.50.121. The monitoring shall be performed when the pig trap is under pressure.~~and according to the requirements in 20.2.50.116 NMAC.~~

(3) An owner or operator complying with Paragraph (1) of Subsection B of 20.2.50.121 NMAC through use of a non-portable control device shall comply with the monitoring requirements in 20.2.50.115 NMAC. A portable control device shall be installed consistent with manufacturer's specifications and is not subject to the requirements of 20.2.50.115 NMAC.

(4) The owner or operator shall comply with the monitoring requirements in 20.2.50.112 NMAC.

Comment on 20.2.50.121(C)(1): Redline required as this has no bearing on emissions from receivers and should be removed.

Comment on 20.2.50.121(C)(2): Redline required to add AVO as an option. Reduces monitoring frequency to no more than once per month and for pigging operations that occur less frequently than monthly, monitoring is performed on a per pigging event basis. Redline added to allow monitoring during representative conditions rather than associated with launching or receiving a pig.

Comment on 20.2.50.121(C)(4). See justification for 20.2.50.121(B)(4).

D. Recordkeeping requirements:

(1) The owner or operator of an affected pig launching and receiving ~~operations~~ site shall maintain a record of the following:

(a) the pigging operation, including the location and date and time of the pigging operation ~~and the type and volume of liquid cleared~~;

(b) the data and methodology used to estimate the actual emissions to the atmosphere and used to estimate the PTE; and

(c) the type of control device and its ~~location~~, make, and model.

(2) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.121 NMAC - N, XX/XX/2021]

20.2.50.122 PNEUMATIC CONTROLLERS AND PUMPS:

NMOGA Comment on 20.2.50.122. Emission Factors for intermittent controllers are incorrect in ERG study, and costs associated with modifications are understated. Cost per ton of VOC in ERG reports is significantly understated. Reference "Valor Memo - Pneumatic Controllers 20.2.50.122" and "Valor Memo - Pneumatic Controllers 20.2.50.122 Emission Factors." NMOGA supports moving away from pneumatic controllers, unless justified as necessary for safety or process control, in an orderly fashion and proposes an approach that does so consistent with parts availability, labor requirements and the sheer number of controllers to be addressed at substantially less cost.

A. Applicability: Natural gas-driven pneumatic controllers and diaphragm pumps permanently located at ~~wellhead sites~~well production facilities, tank batteries, gathering and boosting sites and~~,~~ natural gas processing plants~~, and transmission compressor stations are~~stations are subject to the requirements of 20.2.50.122 NMAC, except for pumps that operate less than 90 days per calendar year.

NMOGA Comment on 20.2.50.122.A:
The changes proposed to reflect definitional changes for greater clarity and to align with NSPS Subpart OOOOa for temporary and sump pumps. Alignment, where possible, reduces confusion and facilitates compliance.

B. Emission standards:

(1) A new well production facility, tank battery, gathering and boosting site, and natural gas processing plant ~~natural gas-driven pneumatic controller or pump~~ shall comply with the requirements of 20.2.50.122 NMAC upon startup.

(2) New well production facilities, tank batteries, gathering and boosting sites, and natural gas processing plans shall have Non-Emitting Controllers installed except as allowed in Paragraph (5) of Subsection B of 20.2.50.122 NMAC. ~~An existing natural gas-driven pneumatic pump shall comply with the requirements of 20.2.50.122 NMAC within three years of the effective date of this Part.~~

(3) Well production facilities and their associated ~~,~~ tank batteries, ~~An existing natural gas-driven~~

~~pneumatic controller~~in existence on the effective date of Part 50 ("pre-effective date") shall comply with the requirements of 20.2.50.122 NMAC according to the ~~following schedule~~schedules set forth in Tables 1 ~~and 2~~ below:

Table 1 – ~~WELLHEAD SITES~~WELL PRODUCTION FACILITIES AND ASSOCIATED~~,~~ TANK BATTERIES~~, GATHERING AND BOOSTING FACILITIES~~

Total Historic ~~Percentage of~~ Non-Emitting Facility Percent Production~~Controllers~~	Total Required ~~Percentage of~~ Non-Emitting Facility Percent Production~~Controllers~~ by January 1, 2024	Total Required ~~Percentage of~~ Non-Emitting Facility Percent Production~~Controllers~~ by January 1, 2027	Total Required ~~Percentage of~~ Non-Emitting Facility Percent Production~~Controllers~~ by January 1, 2030
> 75 %	80%	85%	90%
> 60-75 %	80%	85%	90%
> 40-60 %	65%	70%	80%
> 20-40 %	45%	70%	80%
0-20 %	25%	65%	80%

(a) For purposes of this section, a "Non-Emitting Facility" means a facility with only Non-Emitting Controller except as allowed under Paragraph (5) or (7) of Subsection B of 20.2.50.122 NMAC.

(b) Except as provided in 20.2.50.122.B.(3)(c) or (d), owners or operators of pre-efffective date well production facilities and associated tank batteries shall by January 1, 2023:

(i) Determine the Historic Facility Production for each pre-effective date well production facility by summing the total liquids productions (summing total barrels of oil and water produced through the well production facility) for the calendar year 2020. For a well production facility that does not have a full calendar year of data, then the owner or operator may use 2021 data or an estimate of the anticipated yearly production for the facility based on industry accepted calculation methodologies.

(ii) Calculate the Total Historic Production for the owner or operator by summing the Historic Facility Production for all pre-effective date well production facilities.

(iii) Calculate the Facility Percent Production for each existing facility by dividing the Historic Facility Production by the Total Historic Production.

(iv) Determine the Total Historic Non-Emitting Facility Percent Production by summing the Facility Percent Production for each Non-Emitting Facility as defined in Subparagraph (5)(a) of Subsection B of 20.2.50.122 NMAC. The Total Historic Non-Emitting Facility Percent Production determines an owner or operator's January 1, 2024, January 1, 2027 and January 1, 2030 Total Required Non-Emitting Facility Percent Production as set forth in Table 1, except as provided in subparagraphs (c) or (d) of this Paragraph (3).

(v) Owners and operators must demonstrate compliance with Table 1's January 1, 2024, January 1, 2027 and January 1, 2030 Total Required Non-Emitting Facility Percent Production through any combination of retrofitting pre-effective date well production facilities (and associated tank batteries) to use non-emitting controllers or plugging and abandoning an such well production facility and emptying and decommissioning an associated tank battery. A tank battery that is decommissioned and moved to another location is a new facility for purposes of 20.2.50.122.B.(1) and (2) NMAC.

(c) In lieu of the demonstration required by 20.2.50.122.B.(3)(b) NMAC, an owner or operator may demonstrate that its total oil and natural gas production subject to Part 50 averages fifteen barrels of oil equivalent~~(using a 6 mcf to 1 barrel oil equivalent for natural gas)~~ or less per well per day annual average. To calculate total oil and natural gas production subject to Part 50, an owner or operator must sum all affected oil and natural gas production in calendar year 2020 in barrels of oil equivalent, divide by 365, and divide by the number of affected wells producing hydrocarbons that the owner or operator operated in 2020.

(d) If an owner or operator meets at least seventy-five percent Total Non-Emitting Facility Percent Production by January 1, 2025, table 1 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC does not apply and the owner or operator shall maintain the Total Non-Emitting Facility Percent Production at seventy-five percent or greater thereafter.

(e) High Bleed Controllers shall be retrofitted or replaced no later than January 1, 2024 unless allowed under Paragraph (5) of Subsection B of 20.2.50.122 NMAC.

(4) Pneumatic controllers at gathering and boosting sites and natural gas processing plants existing as of the effective date ("pre-effective date") shall meet the required percentage of non-emitting controllers according to the schedule outlined in Table 2 below:

Table 2 – ~~NATURAL GAS COMPRESSOR STATIONS~~GATHERING AND BOOSTING SITES AND GAS

PROCESSING PLANTS

Total Historic Percentage of Non-Emitting Controllers	Total Required Percentage of Non-Emitting Controllers by January 1, 2024	Total Required Percentage of Non-Emitting Controllers by January 1, 2027	Total Required Percentage of Non-Emitting Controllers by January 1, 2030
> 75 %	80%	95%	98%
> 60-75 %	80%	95%	98%
> 40-60 %	65%	95%	98%
> 20-40 %	50%	95%	98%
0-20 %	35%	95%	98%

~~(4) Standards for natural gas-driven pneumatic controllers.~~

(a) ~~new pneumatic controllers shall have an emission rate of zero.~~

~~(b) existing pneumatic controllers with access to commercial line electrical power shall have an emission rate of zero.~~

(~~c~~b) ~~existing pneumatic controllers at existing facilities~~ Pre-effective date gathering and boosting sites and natural gas processing plants shall phase out natural gas driven pneumatic controller to meet the required percentage of non-emitting controllers within the deadlines in table~~s 1 and~~ 2 of Paragraph (4~~3~~) of Subsection B of 20.2.50.122 NMAC, and shall comply with the following, except as provided in Paragraph (5) of Subsection B of 20.2.50.122 NMAC:

(i) by January 1, 2023, the owner or operator shall determine the total controller count for all controllers at all of the owner or operator's ~~affected facilities~~ pre-effective date gathering and boosting stations and natural gas processing plants subject to Part 50 ~~that commenced construction before the effective date of this Part~~. The total controller count must include all emitting natural gas-driven pneumatic controllers and all non-emitting ~~pneumatic~~ controllers of any type (e.g. mechanical, electric, instrument air-driven, natural gas-driven routed to a combustion device, etc), except that natural gas-driven pneumatic controllers ~~necessary for a safety or process purpose that cannot otherwise be met without emitting natural gas~~ allowed under Paragraph (5) of Subsection B of 20.2.50.122 NMAC shall not be included in the total controller count.

(ii) determine which controllers in the total controller count are non-emitting and sum the total number of non-emitting controllers and designate those as total historic non-emitting controllers.

(iii) determine the total historic non-emitting percent of controllers by dividing the total historic non-emitting controller count by the total controller count and multiplying by 100.

(iv) based on the percent calculated in (iii) above, the owner or operator shall determine which provisions of table~~s 1 and~~ 2 of Paragraph (4~~3~~) of Subsection B of 20.2.50.122 NMAC applies~~y~~ and the retrofit ~~replacement~~ schedule the owner or operator must meet.

(v) if an owner or operator meets at least seventy-five percent total non-emitting controllers by January 1, 2025, ~~the owner or operator has satisfied the requirements of~~ tables ~~1 and~~ 2 of Paragraph (4~~3~~) of Subsection B of 20.2.50.122 NMAC do not apply

(vi) if ~~after January 1, 2027,~~ an owner or operator's remaining pneumatic controllers are not cost-effective to retrofit, the owner or operator shall submit a cost analysis of retrofitting those remaining units to the department. The department shall review the cost analysis and determine whether those units qualify for a waiver from meeting additional retrofit requirements.

(b) High Bleed Controllers shall be retrofitted or replaced no later than January 1, 2024 unless allowed under Paragraph (5) of Subsection B of 20.2.50.122 NMAC.

(5~~dc~~) ~~a natural gas-driven pneumatic controller with a continuous bleed rate greater than six standard cubic feet per hour is permitted when the owner or operator has demonstrated that a higher bleed rate is required based on functional needs, including response time, safety, and positive actuation. An owner or operator that seeks to install an emitting natural gas-driven pneumatic controller at a new facility maintain operation of an emitting pneumatic controller must prepare and document the justification for the safety or process purposes prior to the installation of a new emitting controller or the retrofit of an existing controller. The justification shall be certified by a qualified in-house or professional engineer.~~Pneumatic controllers that emit natural gas to the atmosphere meeting any of the following conditions are not subject to the requirements of Paragraphs (2), (3) or (4) of Subsection B and are not required to be retrofit to count the facility or controller as non-emitting for compliance with Tables 1 and 2 of Subsection B of 20.2.50.122 NMAC.

(a) A natural gas pneumatic controller at a new well production facility, tank battery, gathering and boosting site, or natural gas processing plant or a pre-effective date well production facility and its associated tank batteries classified as a Non-Emitting Facility ~~with a bleed rate greater than six standard cubic feet per 10 hour~~ is permitted when the owner or operator has demonstrated that ~~a higher bleed rate~~it is required based on functional needs, including response time, safety, and positive actuation. An owner or operator that seeks to maintain operation of an emitting pneumatic controller at a new or Non-Emitting Facility must prepare and document the justification for the safety or process purposes prior to the installation of a new emitting controller or the retrofit of an existing controller. The justification shall be certified by qualified maintenance or engineering staff ~~a qualified professional engineer~~.

(b) Pneumatic controllers that emit natural gas located or temporary or portable equipment that is used for well abandonment activities or used prior to or through the end of flowback.

(c) Pneumatic controllers that emit natural gas located on temporary or portable equipment that is on-site and in-use for 90 days or less.

(d) Pneumatic controllers in an automated control system installed to comply with Paragraph (3)(b) of Subsection B of 20.2.50.117 NMAC.

(6~~5~~) Standards for natural gas-driven pneumatic diaphragm pumps.

(a) new pneumatic diaphragm pumps located at a natural gas processing plants shall have a designed natural gas emission rate of zero.

(b) new pneumatic diaphragm pumps located at a ~~wellhead sites~~well production facilities, tank batteries, gathering and boosting sites, or transmission compressor stations with access to commercial line electrical power shall have a natural gas emission rate of zero.

(c) existing pneumatic diaphragm pumps located at a natural gas processing plants shall have a designed natural gas emission rate of zero within 3 years of the effective date of this rule.

(d) existing pneumatic diaphragm pumps located at a well production facilities, storage vessels, gathering and boosting sites, or transmission compressor stations with access to commercial line electrical power shall have a natural gas emission rate of zero within 3 years of the effective date of this rule.

(~~c~~e) ~~owners and operators of~~ Existing pneumatic diaphram pumps located at ~~wellhead sites~~well production facilities, tank batteries, or gathering and boosting sites~~, or transmission compressor stations~~ without access to commercial line electrical power shall reduce VOC emissions from the natural gas-driven pneumatic diaphragm pumps by ninety-five percent if it is technically feasible to route emissions to an existing control device, fuel cell, or process. If there is a control device available onsite but it is unable to achieve a ninety-five percent emission reduction, and it is not technically feasible to route the pneumatic pump emissions to a fuel cell or process, the owner or operator shall route the pneumatic pump emissions to the control device. The rerouting or control device installation must be accomplished within three years.

(7) If after January 1, 2027, an owner or operator's remaining natural gas pneumatic controllers, or if two years after the effective date, an owners or operator's existing natural gas pneumatic diaphragm pumps at a site without commercial line power, are not cost-effective to retrofit, the owner or operator shall submit a cost analysis of retrofitting those remaining units to the department. The department shall review the cost analysis and determine whether those units qualify for a waiver from meeting additional retrofit requirements.

~~**(6)** The owner or operator of a pneumatic controller or pump shall install an EMT on the controller or pump in accordance with 20.2.50.112 NMAC.~~

NMOGA Comments on 20.2.50.122.B:
(1) No "new" pneumatic controllers. NMOGA supports no new natural gas driven pneumatic controllers except in those cases where they are required and justified for safety or specific operational reasons, as recognized in the NM OCD rule, or where there is no technically feasible alternative as approved by the department.
(2) Facility versus controller focus for compliance demonstration. The most common replacement for pneumatic controllers is substitution of instrument air or line or generator-powered electrical controllers. In making such replacements, it is generally not feasible to replace a single pneumatic controller because of the cost of the supporting infrastructure (compressors, generators, transformers, solar panels, etc.), particularly for upstream facilities. Accordingly, for well production facilities and their associated tank batteries, planning at the facility level allows for orderly replacement rather than ad hoc replacement, which is more certain to achieve the desired reductions and will reduce costs.
(2) Well production facilities and associated tank batteries. NMOGA recommends the approach taken in Colorado where production throughput, which correlates to controller releases, is used to plan and track reductions in controllers. This approach determines whether a well production facility and its associated tank batteries are a "Non-Emitting Facility" meaning that all controllers are non-emitting ones unless specifically justified. The percent of historic production passing through Non-Emitting Facilities is then calculated and the owner and operator comply with the required reductions by showing that well production facilities and their associated tank batteries are retrofitted with non-emitting controllers or retired. The proposed redline reflects this change to a production basis. The production basis is easier to track and monitor for compliance than the individual controller basis because the entire facility will use non-emitting controllers (except as allowed under paragraph (5)). Simplicity and clarity will enhance compliance.
(3) Gathering and boosting sites and natural gas processing plants. These facilities are more complex and lend themselves to the controller count approach proposed by NMED and also used in Colorado. Any type of non-emitting controller should be satisfactory to demonstrate compliance, including but not limited to routed pneumatic controllers (e.g.,, those whose exhaust is routed to a process or control device).
(4) NMOGA supports the "early compliance alternative." NMED has proposed to allow facilities that achieve 75% non-

emitting controllers (now 75% of affected production through "Non-Emitting Facilities" under NMOGA's proposal) by January 1, 2025 to stop at 75%. NMOGA supports this plan but believes it should be available to any operator and should not exclude proactive operators who have already achieved the 75% threshold.

C. Monitoring, testing, or inspection ~~-~~requirements:

(1) Pneumatic controllers or diaphragm pumps not using natural gas or other hydrocarbon gas as motive force ~~with a natural gas bleed rate equal to zero~~ are not subject to the monitoring requirements in Subsection C of 20.2.5.122 NMAC.

(2) The owner or operator of a facility with one or more natural gas-driven pneumatic controllers subject to the deadlines set forth in ~~tables~~ Tables 1 and 2 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC shall monitor the compliance status of each subject pneumatic controller at each facility.

(3) The owner or operator of a natural gas-driven pneumatic controller ~~with a bleed rate greater than zero~~ shall, on a monthly basis, ~~scan the controller and~~ conduct an AVO or OGI inspection, and ~~shall also inspect the pneumatic controller,~~ perform necessary maintenance ~~and maintain~~ on the natural gas-driven pneumatic controller according to manufacturer specifications to ensure that the VOC emissions are minimized.

(4) For any natural gas-driven pneumatic controller remaining in operation after January 1, 2030, the owner or operator shall maintain an inventory containing the following:~~The EMT shall be linked to a database that contains the following~~:

(a) natural gas-driven pneumatic controller identification number;

(b) type of controller (continuous or intermittent);

(c) if continuous, design continuous bleed rate in standard cubic feet per hour;

(d) if intermittent, bleed volume per intermittent bleed in standard cubic feet.~~; and~~

~~**(e)** design annual bleed in standard cubic feet per year.~~

(5) The owner or operator of a natural gas-driven pneumatic diaphragm pump ~~with bleed rate greater than zero~~ shall, on a monthly basis, ~~scan the pump and~~ conduct an AVO or OGI inspection and ~~shall also inspect the pneumatic pump and~~perform necessary maintenance ~~, and maintain~~on the pneumatic pump ~~according to manufacturer specifications~~ to ensure that the VOC emissions are minimized.

(6) The owner or operator shall monitor the oil and gas and liquid production through each well production facility and any associated tank batteries in calendar year 2020, or of the method used to calculate production if a full year of data are not available for calendar year 2020 as set forth in Paragraph (3)(b) of Subsection B of 20.2.50.112 NMAC.

(7~~6~~) The owner or operator shall comply with the monitoring requirements in 20.2.50.112 NMAC.

NMOGA comments on 20.2.50.122.C
The proposed changes implement the recommendations made for subsection B. The change to C.(1) clarifies that monitoring does not apply to instrument air or other controllers that don't use natural gas or other hydrocarbon gas. This means that routed controllers are still subject to AVO requirements. Other changes allow OGI inspections in addition to AVO and set inventory requirements for any natural gas pneumatic controllers that will remain in place after the phase out.

D. Recordkeeping requirements:

(1) Non-emitting ~~Pneumatic~~ controllers and pumps ~~with a natural gas bleed rate equal to zero~~ are not subject to the recordkeeping requirements in Subsection D of 20.2.5.122 NMAC.

(2) The owner or operator shall maintain a record of each pre-effective date well production facility and associated tank battery, its calendar year 2020 total liquids production, the calendar year 2020 total oil and gas production at all existing well production facilities subject to Part 50, whether the well production facility and associated tank battery was a Non-Emitting Facility in 2020 and its status in the current calendar year, and the 2020 liquid throughput for each well production facility and associated tank battery. An owner an operator complying with Table 1 of Paragraph (3) of Subsection B shall, beginning in calendar year 2022 each year through calendar year 2031, calculate its Non-Emitting Facility Percent Production as set forth in Paragraph (3)(b) of Subsection B except substituting the reporting year's Non-Emitting Facilities multiplied by the 2020 Facility Percent Production in the numerator and dividing by the owner or operator's 2020 Total Historic Production in the denominator.

(3) The owner or operator of existing well production facilities complying with the limitation on daily average per well production set forth in Paragraph (3)(c) of Subsection B shall keep its calculation of its daily average production as required under Paragraph (3)© of Subsection B of 20.2.50.122 NMAC..

(4) The owner or operator shall maintain a record for each pre-effective date gathering and boosting site and natural gas plant of the total controller count ~~for all controllers at all of the owner's or operator's affected facilities that commenced operation before the effective date of this Part. The total controller count must include~~of all emitting and N~~n~~on-E~~e~~mitting ~~pneumatic~~ C~~c~~ontrollers. An owner an operator complying with Table 2 of Paragraph (3) of Subsection B shall, beginning in calendar year 2022 each year through calendar year 2031, calculate its Percentage of Non-Emitting Controllers as set forth in Paragraph (4) of Subsection B except substituting the calendar year's count of Non-Emitting Controllers in the numerator and retaining the 2020 count of total controllers in the denominator.

(5~~3~~) The owner or operator shall maintain a record of the total count of natural gas-driven pneumatic controllers allowed under Paragraphs (5) or (7) of Subsection B of 20.2.50.122 ~~necessary for a safety or process purpose that cannot otherwise be met without emitting VOC~~.

(6~~4~~) The owner or operator of a natural gas-driven pneumatic controller subject to the requirements in ~~tables~~ Tables 1 and 2 of Paragraphs (3) and (4) ~~of~~ shall generate a schedule for meeting the compliance deadlines ~~for each pneumatic controller. The owner or operator shall keep a record of the compliance status of each subject controller.~~set forth therein.

(7~~5~~) The owner or operator shall maintain an electronic record for each natural gas pneumatic controller ~~with a natural gas bleed rate greater than zero~~. The record shall include the following:

(a) pneumatic controller identification number;

(b) inspection dates;

(c) name of the ~~personnel~~ person(s) conducting the inspection;

(d) AVO or OGI inspection result;

(e) ~~AVO or OGI level discrepancy in continuous or intermittent bleed rate;~~

(f) maintenance date and maintenance activity; and

(g) a record of the justification and certification required in Subparagraph (d) of Paragraph (4) of Subsection B of 20.2.50.122 NMAC.

(8~~6~~) The owner or operator of a natural gas-driven pneumatic controller ~~with a design bleed rate greater than six standard cubic feet per hour~~ allowed under Paragraphs (5) or (7) of subsection B of 20.2.50.122 shall maintain a record ~~in the EMT database~~ of the pneumatic controller documenting ~~why a bleed rate greater than six scf/hr is necessary~~the justification, as required in Subsection B of 20.2.50.122 NMAC.

(9~~7~~) The owner or operator shall maintain a record ~~in the EMT database~~ for a natural gas-driven pneumatic diaphram pump with an emission rate greater than zero and the associated pump number at the facility. The record shall include:

(a) for a natural gas-driven pneumatic diaphragm pump in operation less than 90 days per calendar year, a record for each day of operation during the calendar year.

(b) a record of any control device designed to achieve at least a ninety-five percent emission reduction, including an evaluation or manufacturer specifications indicating the percentage reduction the control device is designed to achieve.

(c) records of the engineering assessment and certification by a qualified in-house employee or professional engineer that routing pneumatic pump emissions to a control device, fuel cell, or process is technically infeasible.

(10~~8~~) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

(11) The owner or operator of a pre-effective date facility subject to Table 1 or Table 2 of Subsection B of 20.2.50.122 NMAC must retain records of its calculations until two years after compliance with the January 1, 2030 requirement in Table 1 or Table 2, as applicable, is achieved and reported to the department.

NMOGA comments on 20.2.50.122.D
Change to D.(1) reflects new terminology.
New D.(2) provides recordkeeping to calculate required percent production reduction and progress toward the phase out goals set in Table 1 for well production facilities and their associated tank batteries.
New D.(3) requires that an owner or operator complying with the paragraph B.(3)(c) (less than 15 barrels of oil equivalent per day) alternative must keep the demonstration of compliance required by that paragraph.
New D.(4) provides recordkeeping to calculate the required reduction in the percent of pneumatic controllers at gathering and boosting sites and natural gas processing plants.
New D.(11) states how long these records must be kept after the phase down is complete.

E. Reporting requirements:

(1) An owner or operator with pre-effective date well production facilities and associated tank batteries complying with Subparagraph (b) or (d) of Paragraph (3) of Subsection B shall submit a Well Production Facility/Tank Battery Pneumatic Controller Compliance Plan on a Department-approved form by January 1, 2023 including:

(a) For each pre-effective date well production facility and associated tank battery, the Historic Facility Production, Facility Percent Production, both calculated in accordance with Paragraph (3) of Subsection B, whether the facility is a Non-Emitting Facility, and the API number for each well production facility.

(b) The Total Historic Production, Total Historic Non-Emitting Facility Percent Production, both calculated in accordance with Paragraph (3) of Subsection B, and the schedule of Total Required Non-Emitting Facility

Percent Production applicable to the owner and operator pursuant to Table 1 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC.

(c) The planned schedule developed under Paragraph (5) of Subsection D of 20.2.50.122 NMAC.

(2) An owner or operator with pre-effective date well production facilities and associated tank batteries complying with Subparagraph (c) of Paragraph (3) of Subsection B shall submit a Low Production Well Declaration on a Department approved form by January 1, 2023 including:

(a) A statement of the 2020 hydrocarbon production for each existing well production facility by API number, in barrels of oil equivalent.

(b) A summation of the 2020 total hydrocarbon production in barrels of oil equivalent from all existing well production facilities subject to Part 50, with this sum divided by 365 and showing that the 2020 annual average production was less than 15 barrels of oil equivalent.

(3) An owner or operator with pre-effective date gathering and boosting sites or natural gas processing plants shall submit a Gathering and Boosting Site/Natural Gas Processing Plant Pneumatic Controller Compliance Plan on a Department-approved form by January 1, 2024 including:

(a) For each pre-effective date gathering and boosting site or natural gas processing plant, the total count of controllers at that site or plant, including the count of pneumatic controllers, non-emitting controllers, and controllers allowed under Paragraph (5) of Subsection B.

(b) For all pre-effective date gathering and boosting sites or natural gas processing plants subject to Part 50 operated or owned, the total count of controllers, including the count of pneumatic controllers, non-emitting controller, and controllers allowed under Paragraph (5) of Subsection B, and the schedule of Total Historic Non-Emitting Controller Percentage applicable to the owner and operator pursuant to Table 2 of Paragraph (4) of Subsection B of 20.2.50.122 NMAC.

(c) The planned schedule developed under Paragraph (5) of Subsection D of 20.2.50.122 NMAC.

(4) Each year beginning on July 1, 2023 and continuing until compliance with Table 1 of Subsection B is achieved, an owner and operator with pre-effective date well production facilities and associated tank batteries subject to Table 1 of Subsection B shall submit an Annual Well Production Facility/Tank Battery Pneumatic Compliance Report for the prior calendar year on a department approved form. The report shall:

(a) Identify the owner and operator and the year for which the report is submitted.

(b) Identify the number of well production facilities (including associated tank batteries) that were retrofitted to become Non-Emitting Facilities, well production facilities and associated tank batteries that were plugged and abandoned and the tank battery decommissioned, including the month of plugging and/or decommissioning.

(c) A calculation of the Non-Emitting Facility Percent Production calculated for the prior calendar year using the procedures in Paragraph (2) of Subsection D of 20.2.50.122 NMAC and a comparison to the currently applicable standard in Table 1.

(d) A revised Well Production Facility/Tank Battery Pneumatic Controller Compliance Plan as set forth in Paragraph (5) of Subsection D if the Total Required Non-Emitting Facility Percent Production required by Table 1 has not been met.

(5) Each year beginning on July 1, 2023 and continuing until compliance with Table 2 of Subsection B is achieved, an owner and operator of pre-effective date gathering and boosting sites or natural gas production plants subject to Table 2 of Subsection B shall submit an Annual Gathering and Boosting Site/Natural Gas Production Plant Pneumatic Compliance Report for the prior calendar year on a department approved form. The report shall include:

(a) Identify the owner and operator and the year for which the report is submitted.

(b) Identify the number of natural gas driven pneumatic controllers that were retrofitted to non-emitting controllers, or that were decommissioned, including the month of plugging or decommissioning.

(c) A calculation of the Percent Non-Emitting Controllers calculated for the prior calendar year using the procedures in Paragraph (3) of Subsection D of 20.2.50.122 NMAC and a comparison to the currently applicable standard in Table 2.

(d) A revised Gathering and Boosting Site/Natural Gas Processing Plant Pneumatic Compliance Plan as set forth in Paragraph (5) of Subsection D if the Total Required Percent Non-Emitting Controllers required by Table 2 has not been met.

(e) The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.122 NMAC - N, XX/XX/2021]

NMOGA comments on 20.2.50.122.E
New E.(1)-(3) reports. These paragraphs require an initial report to the department by January 1, 2023 of the applicable standards and schedules for each owners or operator's pre-effective date facilities. This provides the department with assurance that each owner/operator has a compliance plan and schedule in place to meets its obligations under Subsection B.

New E.(4)-(5) reports. These paragraphs require an annual report showing each owner and operator's progress toward compliance with the schedules under Tables 1 or 2 for pre-effective date facilities. The annual report provides added assurance to the department that the obligations of Tables 1 and 2 will be met.

20.2.50.123 STORAGE VESSELS

A. Applicability: Existing single storage vessel and existing multiple storage vessel tank batteries where individual tank uncontrolled PTE is equal to or greater than six tpy of VOC, and new single storage vessel and new multiple storage vessel tank batteries where individual tank uncontrolled PTE is equal to or greater than two tpy of VOC, located at. ~~Storage vessel(s) with an uncontrolled PTE equal to or greater than two tpy of VOC and located at wellhead sites~~tank batteries located at well production facilities, ~~tank batteries~~, gathering and boosting sites, natural gas processing plants, or transmission compressor stations are subject to the requirements of 20.2.50.123 NMAC. In determining the individual tank uncontrolled PTE, owners or operators will use generally accepted methods for estimating emissions. Where multiple storage vessels are manifolded together with piping such that all vapors are shared between the headspace of the storage vessels and are routed to a common outlet or end point, owners or operators may determine individual storage vessel emissions by averaging the emissions across the total number of storage vessels in the tank battery. The requirements of 20.2.50.123 NMAC do not apply to storage vessels subject to the requirements for storage vessels in 40 CFR part 60, subpart Kb, OOOO, and OOOOa, and 40 CFR part 63, subparts G, CC, HH, or WW.

Comment on 20.2.50.123(A): Redline required to align with proposed changes per the Valor Memo - Storage Vessels 20.2.50.123. Redline regarding averaging emissions across manifolded tank batteries is required to provide a reasonable methodology for determining potential emissions and rule applicability for such configurations. Where multiple manifolded storage vessels share headspace and are routed to a common end point, emissions from each respective tank are indistinguishable from one another. Where such configurations are routed to and controlled by a common control device, emissions from all tanks achieve the same destruction efficiency. Consequently, determining emissions for each respective tank by averaging the potential emissions rate across the number of units in the battery is an appropriate measure of each unit's potential emissions. Where the average VOC emissions across the number of storage vessels in the controlled battery is equal to or greater than the applicability threshold, all of the storage vessels in the controlled battery are subject to the standard. However, where the average emissions are less than the applicability threshold, none of the storage vessels in the controlled battery are subject to the standard. This is the approach EPA has taken for determining applicability under 40 C.F.R. Part 60, Subpart OOOOa. See 85 Fed. Reg. 57398, 57411 (Sept. 15, 2020).

B. Emission standards:

(1) An existing storage vessel with a PTE equal to or greater than ~~two~~ six tpy ~~and less than 10~~tpy of VOC shall have a combined capture and control of VOC emissions of at least ninety-five percent no later than three years after the effective date of this Part.

~~**(2)** An existing storage vessel with a PTE equal to or greater than 10 tpy of VOC shall have a combined capture and control of VOC emissions of at least ninety-eight percent no later than one year after the effective date of this Part.~~

(3) A new storage vessel with a PTE equal to or greater than two tpy ~~and less than 10 tpy~~ of VOC shall have a combined capture and control of VOC emissions of at least ninety-five percent upon startup.

~~**(4)** A new storage vessel with a PTE equal to or greater than 10 tpy of VOC shall have a combined capture and control of VOC emissions of at least ninety-eith percent upon startup.~~

(5) The emission standards in Subsection B of 20.2.50.123 NMAC cease to apply to a storage vessel if the uncontrolled actual annual VOC emissions decrease to less than two tpy for new tanks and four tpy for existing tanks.

(6) If a control device is not installed by the date specified in Paragraphs (1) through (4) of Subsection B of 20.2.50.123 NMAC, an owner or operator may comply with Subsection B of 20.2.50.123 NMAC by shutting in or reducing production from the well supplying the storage vessel by the applicable date such that the uncontrolled annual emissions are less than two tpy for new tanks and four tpy for existing tanks, and not resuming or increasing production from the well until the control device is installed and operational or the Department has approved an extension of the deadline.

(7) The owner or operator of a new or existing storage vessel with a thief hatch ~~shall install a control device that allows the~~ shall ensure that the thief hatch is capable of ~~to~~ opening sufficiently to relieve overpressure in the vessel and to automatically close once the vessel overpressure is relieved. Owners and operators may also install other pressure relief devices to ensure that overpressure can be adequately relieved. Any pressure relief device installed must automatically close once the vessel overpressure is relieved. ~~The thief hatch shall be equipped with a manual lock- open safety device to ensure positive hatch opening during times of human ingress. The lock-open safety device shall only be engaged when an owner or operator are present and during an active ingress activity.~~

~~**(8)** The owner or operator of a new or existing storage vessel shall install an EMT on the storage vessel in accordance with 20.2.50.112 NMAC.~~

(9) An owner or operator complying with Paragraphs (1) through (4) of Subsection B of 20.2.50.123

NMAC through use of a control device shall comply with the control device operational requirements in 15 20.2.50.115 NMAC.

Comment on 20.2.50.123(B)(2), (4): Redline required as this effectively prohibits the use of thief hatches. If we assume that the control device has 98% destruction efficiency you would need to have 100% capture to meet this requirement. There is 0% capture any time a hatch is open and hence hatches are effectively being banned by this requirement.

Comment on 20.2.50.123(B)(7): Redline required as there is no such thing as a control device that allows a thief hatch to open. Furthermore, any device allowing a thief hatch to open to atmosphere would be creating emissions and would be the opposite of a thief hatch. Redline required as a storage tank is a confined space, if there ever needs to be "human ingress" the tank will need to be drained and the manway removed to provide access. At that point there is no need to worry about whether a thief hatch is opened or closed as the tank will no longer contain any liquids.

C. **Monitoring requirements:** The owner or operator of a storage vessel shall:

(1) ~~monitor~~ on a monthly basis, calculate or estimate the total monthly liquid throughput (in barrels) and record the upstream separator pressure (in psig) if the storage vessel is directly downstream of a separator. When a storage vessel is unloaded less frequently than monthly, the throughput and separator pressure monitoring shall be conducted before the storage vessel is unloaded;

~~**(2)** conduct an AVO inspection on a weekly basis. If the storage vessel is unloaded less frequently than weekly, the AVO inspection shall be conducted before the storage vessel is unloaded;~~

~~**(3)** inspect the vessel monthly to ensure compliance with the requirements of 20.2.50.123 NMAC. The inspection shall include a check to ensure the vessel does not have a leak;~~

~~**(4)** scan the EMT and enter the required monitoring data in accordance with the requirements 25 of 20.2.50.112 NMAC;~~

(2) comply with the monitoring requirements in 20.2.50.115 NMAC if using a control device to comply with the requirements in Paragraphs (1) through (4) of Subsection B of 20.2.50.123 NMAC; and

(3) comply with the monitoring requirements in 20.2.50.112 NMAC.

Comment on 20.2.50.123(C)(1): Redline in (C)(1) necessary because operators do not monitor throughput to each and every tank, but estimate or calculate the monthly liquid throughput through each tank based on total throughput through the manifolded vessel.

Comment on 20.2.50.123(C)(2)-(3): Redline required as 2 and 3 are duplicative of 20.2.50.116.

D. **Recordkeeping requirements:**

(1) The owner or operator shall, on a monthly basis, maintain a record in accordance with 20.2.50.112 NMAC for a storage vessel. The record shall include:

(a) the vessel location and identification number;

(b) calculated or estimated monthly liquid throughput; ~~and the most recent date of measurement;~~

(c) the ~~average monthly~~ upstream separator pressure, where applicable;

(d) the data and methodology used to calculate the actual emissions of ~~PTE~~ of VOC (~~the Calculation methodology shall be department approved);~~

(e) the controlled and uncontrolled VOC emissions (tpy); and

(f) the type, make, model, and identification number of any control device.

(2) A record of liquid throughput in shall be ~~verified~~ estimated by liquid level measurements, a dated delivery receipt from the purchaser of the hydrocarbon liquid, the metered volume of hydrocarbon liquid sent downstream, or other proof of transfer.

(3) A record of the inspection required in Subsection C of 20.2.50.123 NMAC shall include:

(a) the time and date of the inspection;

(b) the ~~personnel~~ person(s) conducting the inspection;

~~**(c)** a notation that the required leak check was completed;~~

(~~d~~c) a description of any problem observed during the inspection; and

(~~e~~d) a description and date of any corrective action taken.

(4) An owner or operator complying with the requirements in Paragraphs (1) through (4) of Subsection B of 20.2.50.123 NMAC through use of a control device shall comply with the recordkeeping requirements in 20.2.50.115 NMAC.

(5) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

Comment on 20.2.50.123(D)(1)(b): Redline required as this data point has limited to no value.

Comment on 20.2.50.123(D)(1)(c): Redline required as operator is only required to monitor upstream separator pressure monthly, so shouldn't be required to keep record of "average monthly" separator pressure.

Comment on 20.2.50.123(D)(1)(d): Redline required as PTE is a one-time calculation so there is no reason to track the calculation method monthly. The intent is to probably record the method for calculating actual monthly emissions required in (e). Redline required as it is the operators' responsibility to develop methodology using best industry/engineering practices and present the findings to the Department.

Comment on 20.2.50.123(D)(2): Redline required as this addition is necessary as there would be no way to determine tank throughput for a tank that doesn't have a load hauled within a month and because, within tank batteries, operations do not measure throughput to each tank, but would estimate or calculate the monthly liquid throughput through each tank based on total throughput

Comment on 20.2.50.123(D)(3)(c): Redline required as the inspection itself is the required leak check, making this notation redundant.

E. Reporting requirements:

(1) An owner or operator complying with the requirements in Paragraphs (1) through (4) of Subsection B of 20.2.50.123 NMAC through use of a control device shall comply with the reporting requirements in 20.2.50.15 NMAC.

(2) The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.123 NMAC - N, XX/XX/2021]

20.2.50.124 WELL WORKOVERS

A. Applicability: Workovers performed at oil and natural gas wells are subject to the requirements of 20.2.50.124 NMAC as of the effective date of this Part.

B. Emission standards: The owner or operator of an oil or natural gas well shall use the following best management practices during a workover to minimize emissions, consistent with the well site condition and good ~~engineering~~ operational practices:

(1) reduce wellhead pressure before blowdown to minimize the volume of natural gas vented;

(2) monitor manual venting at the well until the venting is complete; and

(3) route natural gas to the sales line, if possible.

C. Monitoring, testing or inspection requirements:

(1) The owner or operator shall monitor the following parameters during a workover:

(a) wellhead pressure;

(b) flow rate of the vented natural gas (to the extent feasible); and

(c) duration of venting to the atmosphere.

(2) The owner or operator shall calculate the estimated volume and mass of VOC vented during a workover.

(3) The owner or operator shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator shall keep the following record for a workover:

(a) identification number and location of the well;

(b) date the workover was performed;

(c) wellhead pressure;

(d) flow rate of the vented natural gas to the extent feasible, and if measurement of the flow rate is not feasible, the owner or operator shall use the maximum potential flow rate in the emission calculation;

(e) duration of venting to the atmosphere;

(f) description of the management practices used to minimize release of VOC before and during the workover; and

(g) calculation of the estimated VOC emissions vented during the workover based on the duration, volume, and ~~mass~~ gas composition of VOC.

(2) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements

(1) The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

(2) If it is not feasible to prevent VOC emissions from being emitted to the atmosphere from a workover event, the owner or operator shall notify by certified mail all residents located within one-quarter mile of the well of the planned workover at least three calendar days before the workover event.

(3) Notification exception for ~~emergency~~ routine downhole maintenance operations to restore production lost due to upsets or equipment malfunction, allowing the owner or operator to notify all residents located within one-quarter mile of the well of the planned workover at least 24 hours before the workover event.

[20.2.50.124 NMAC - N, XX/XX/2021]

Comment on 20.2.50.124(C)(1)(2), (D)(1)(g): Redline required because well liquids unloading vented gas is calculated, not measured, and calculations may involve some degree of estimation.

Comment on 20.2.50.124(E)(2)-(3): Redline required as certified mail delivery times vary, and this requirement does not allow for more advanced technology or concepts.

Comment on 20.2.50.124(E)(3): Redline required as routine downhole maintenance workovers are downhole intervention activities that are required to restore production from a well by performing downhole maintenance or repair which would include but is not limited to a pump change, tubing swap or clean out. This would not include pay adds or recompletion type workovers. This exception is necessary to allow for the flexibility to perform routine downhole maintenance and not have an unnecessary delay with the notification process. The efficient use of a workover rig in the field requires this flexibility to ensure wells in an area can be serviced while a rig is in close proximity.

~~**20.2.50.125 SMALL BUSINESS FACILITIES**~~

~~**A. Applicability:** Small business facilities as defined in this Part are subject to the requirements of 20.2.50.125 NMAC.~~

~~**B. General requirements:**~~

~~**(1)** The owner or operator shall ensure that all equipment is operated and maintained consistent with manufacturer specifications, and good engineering and maintenance practices. The owner or operator shall keep manufacturer specifications and maintenance practices on file and make them available to the department upon request.~~

~~**(2)** The owner or operator shall calculate the VOC and NOx emissions from the facility on an annual basis. The calculation shall be based on the actual production or processing rates of the facility.~~

~~**(3)** The owner or operator shall maintain a database of company-wide VOC and NOx emission calculations for all subject facilities and associated equipment and shall update the database annually.~~

~~**(4)** The owner or operator shall comply with Paragraph (10) of Subsection A of 20.2.50.112 NMAC if requested by the department.~~

~~**C. Monitoring requirements:** The owner or operator shall comply with the requirements in Subsections C or D of 20.2.50.116 NMAC.~~

~~**D. Repair requirements:** The owner or operator shall comply with the requirements of Subsection E of 20.2.50.116 NMAC.~~

~~**E. Recordkeeping requirements:** The owner or operator shall maintain the following electronic records for each facility:~~

~~**(1)** annual certification that the small business facility meets the definition in this Part;~~

~~**(2)** calculated VOC and NOx emissions from each facility and the company-wide VOC and NOx emissions for all subject facilities;~~

~~**(3)** records as required under Subsection F of 20.2.50.116 NMAC.~~

~~**F. Reporting requirements:** The owner or operator shall submit to the department an initial small business certification within sixty days of the effective date of this Part, and by March 1 each calendar year thereafter. The certification shall be made on a form provided by the department. The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.~~

~~**G. Failure to comply with 20.2.50.125 NMAC:** Notwithstanding the provisions of Section 20.2.50.125 NMAC, a source that meets the definition of a small business facility can be required to comply with the other Sections of 20.2.50 NMAC if the Secretary finds based on credible evidence that the source (1) presents an imminent and substantial endangerment to the public health or welfare or to the environment; (2) is not being operated or maintained in a manner that minimizes emissions of air contaminants; or (3) has violated any other requirement of 20.2.50.125 NMAC.~~

~~[20.2.50.125 NMAC - N, XX/XX/2021]~~

Comment on 20.2.50.125. NMOGA cannot identify any oil and gas owners or operators in the state that qualify under NMED's definition of a small business facility. While it is appropriate to take steps to reduce the economic impact of the rule on small operators, the employee and financial thresholds would need to be increased to achieve this objective.

20.2.50.126 PRODUCED WATER MANAGEMENT UNITS

A. Applicability: Produced water management units as defined in this Part are subject to 20.2.50.126 NMAC and shall comply with these requirements no later than 180 days after the effective date of this Part.

B. Emission standards:

(1) The owner or operator shall use best management and good ~~engineering~~ operational practices to minimize emissions of VOC from produced water management units.

(2) The owner or operator shall calculate uncontrolled PTE for each produced water management unit. If the PTE exceeds the threshold specified in 20.2.73.200 the owner or operator shall submit a Notice of Intent to NMED for approval. If the PTE exceeds thresholds established in 20.2.72.200 ~~control~~ file an appropriate permit application ~~VOC emissions from~~for each produced water management unit. Existing produced water management units with uncontrolled PTE that exceeds the thresholds in 20.2.73.200 or 20.2.72.200 may continue to operate until the application is approved or denied by the Department. ~~to less than two tons per year.~~

C. Monitoring, inspection or testing requirements: The owner or operator shall:

(1) calculate the monthly rolling 12-month total of VOC emissions in tons from each unit with first month of emission calculation beginning within 180 days after the effective date of this Part;

(2) monthly, monitor the best management and ~~engineering~~ operational practices implemented to reduce emissions at each unit to ensure their effectiveness; and

(3) comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator shall maintain the following electronic records for each produced water management unit:

(a) name or identification of the unit and UTM coordinates of the unit and county;

(b) a description of the best management and ~~engineering~~operational practices used to minimize release of VOC at the produced water management unit; and

(c) a record of the monthly rolling 12-month total VOC emissions from each produced water management unit.

(2) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.126 NMAC - N, XX/XX/2021]

Comment on 20.2.50.126(B)(2): As NMOGA communicated on the pre-proposal, there are operational and technical design infeasibilities with installing and maintaining barrier controls to reduce emissions on large ponds. In addition, there is a lack of data to show effective emission reductions that could be placed on the Produced Water Ponds, in lieu of reducing produced water recycling, to achieve two tons per year. These Produced Water Management Units are integral to recovering and treating produced water for reuse, and this proposed emission limit would reduce or eliminate the goal of recycling produced water for drilling operations, inconsistent with the Legislature's intent in the Produced Water Act. To move towards improving NMED's emission inventory and operational data set on these Produced Water Management Units, NMOGA proposes to update a current General Construction Permit (GCP) to include Produced Water Management Units. Until the GCPs have been updated to include Produced Water Management units, NMOGA suggests utilizing the current NOI and permitting processes to continue management of these facilities.

Comment on 20.2.50.126(C)(1): Redline required as monthly data will not be available immediately at the effective date, therefore time is needed to accumulate data.

20.2.50.127 PROHIBITED ACTIVITY AND CREDIBLE INFORMATION PRESUMPTION

A. Failure to comply with the emissions standards, monitoring, testing, inspection, recordkeeping, reporting or other requirements of this Part within the timeframes specified shall constitute a violation of this Part subject to enforcement action under Section 74-2-12 NMSA 1978.

B. If credible evidence~~information~~ obtained by the department demonstrates an alleged violation ~~indicates that a source is not in compliance with~~of the provisions of this Part, the source shall have an opportunity to provide ~~be presumed to be in violation of this Part unless and until the owner or operator provides~~ credible evidence or information demonstrating otherwise.

C. If ~~credible~~ information is provided to the department by a member of the public ~~indicates~~ indicating that a source may~~is~~ not be in compliance with the provisions of this Part, the Department may initiate enforcement action under Section 74-2-12 NMSA 1978 only if the Department determines the information is of sufficient value and credibility and demonstrates that a violation occurred. In evaluating whether the information is of sufficient value and credibility of information provided by a member of the public and determining the use of such information as evidence in an enforcement action, the Department shall consider the following criteria:

(1) the member of the public providing the information must be willing to submit a sworn affidavit attesting to the facts that constitute the alleged violation and authenticating any writings, recordings, or photographs provided by the individual;

(2) the individual providing the information must be willing to make themselves available to the Department and alleged violator regarding the alleged violation, including as necessary to testify in any enforcement proceedings regarding the alleged violations;

(3) if the Department relies on any physical or sampling data submitted by an individual to prove one or more elements of an enforcement case, such data must have been collected or gathered in accordance with relevant agency protocols and the individual must be willing to submit a sworn affidavit demonstrating that it followed relevant agency protocols when collecting the data,~~;~~ and the Department must ensure that the physical or sampling data was collected through an accepted and verifiable methodology.

(4) the Department will not use in an enforcement action information gathered by an individual illegally, including pursuant to trespass.

~~the source shall be presumed to be in violation of this Part unless and until the owner or operator provides credible evidence or information demonstrating otherwise.~~

[20.2.50.127 NMAC - N, XX/XX/2021]

Comment on 20.2.50.127. NMOGA opposes subsections 20.2.50.127(B) and (C) of the proposed rule. The proposed rule would establish a presumption of noncompliance based on "credible information" received from a third-party and allow enforcement actions to be brought only based upon indication of noncompliance. However, the rule fails to define "credible information" and "credible evidence," and places potentially insurmountable burdens on operators to provide evidence to rebut an allegation by either the Department or the public.

Information used for enforcement must be scientifically reliable, legally defensible, and subject to defined methods of detection and reporting. The proposed rule fails to meet these minimum criteria and would establish a presumption of noncompliance based on undefined "credible information" received from a third party or just indications of non-compliance from the agency. The proposed rule similarly fails to define what will be considered "credible evidence" sufficient to rebut this presumption. This lack of specificity places potentially insurmountable burdens on operators to provide evidence to rebut an allegation by either the Department or the public. More specifically:

1. "Credible Information" and "Credible Evidence" are not defined terms. "Credible information" would apply to information obtained by NMED and information provided to NMED by the public. "Credible evidence or information" would apply to rebuttal of "credible information." It is unclear whether these meant to be the same, regardless of who obtains the information, or different?

2. The breadth of compliance information already submitted and readily available to the Department weighs against a presumption of noncompliance based on third-party information. This is particularly so given that the third-party "credible information" is not subject to any requirements related to quality control—e.g., data collection method, chain of custody documentation, etc. Technology to detect emissions is evolving (satellites, flyovers, drones, etc.) and the oil and gas industry has partnered with vendors, NGOs and academic institutions to assess the usefulness of new technology. However, many of these alternative methods of detection are not commonly available or not yet capable of providing data that can be used to determine compliance. New technologies have shown great promise in detecting emissions at a lower cost, but there is generally a trade off in terms of detection limit and ability to pinpoint the location of a leak. Thus, the agency must demonstrate that the data is of sufficient value and credibility and that a violation has occurred before it may bring an

enforcement action.
3. Regardless of the method of detection, it is critical to understand how to use the technology and to ensure that it is properly functioning and calibrated so that the resulting data is reliable and, if necessary, replicable. Users must document how the method was used, confirm the tool was working correctly, and demonstrate a chain of custody. The Department must demonstrate that each of the above indicates that a violation has occurred before it may bring an enforcement action.
5. If an operator does not obtain the "credible information" until days, weeks, months or years after it was created, it will be difficult, if not impossible, to verify (or refute) the credibility of the information through subsequent investigation. Thus, the Department must not assume a violation based upon this data, but must evaluate the data to determine if it in fact is sufficient value and credibility to demonstrate a violation.
6. Without establishing minimum criteria and a requirement for the Department to determine a violation in fact occurred, the burden of proof for credibility is a low and easy threshold to surpass, allowing almost any type of accusation of non-compliance by NMED or the public to be alleged.
7. Encouraging submission of "credible information" by the public, without any safeguards or limitations, will undoubtedly create situations that put members of the public in immediate danger, as well as operators' employees and contractors. During state and federal regulatory or enforcement agency inspections, an operator representative must be allowed to accompany a trained, experienced inspector. Encouraging citizen inspections, without appropriate safeguards, may lead to situations where untrained, inexperienced members of the public are trespassing by attempting to enter on or come near facilities to collect information, putting not only themselves, but operators and other community members at risk.

HISTORY OF 20.2.50 NMAC: [**RESERVED**]